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Impact of Natural Gas Curtailments on Electric Utility Plants
Volume I. Text

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Environmental Protection Agency, Research Triangle Park, N C Office of Air Quality Planning and Standards

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IMPACT OF NATURAL GAS CURTAILMENTS ON ELECTRIC UTILITY PLANTS
VOLUME I - TEXT

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This study was conducted to analyze the impact of natural gas curtailments on electric utility plants through the review of the curtailment plans of interstate pipeline, intrastate pipeline and gas distributors. This analysis determined the availability of natural gas through 1980 to 415 electric utility power plants, the alternate fuel burning capability of these plants and the impact of gas curtailments on the need for alternate fuels such as fuel oil and coal. The study results are presented in a two volume report: the first contains the narrative with pertinent findings and conclusions; the second contains the schedules or data summaries.

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VOLUME I - TEXT

by

Energy Division
Foster Associates, Inc.
Washington, D. C.

Contract No. 68-02-1452
Task No. 1

EPA Project Officer: Rayburn Morrison

Prepared for

ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
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Research Triangle Park, North Carolina 27711

August 1975

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INTRODUCTION

In light of the worsening gas shortage, federal and state regulatory agencies have promulgated policies with respect to the distribution of gas sales when demand exceeds supply. Gas companies in turn have implemented or are about to implement specific curtailment plans, the results of which have a significant impact on natural gas consumption by electric utilities and industrial concerns and thus could affect air quality by requiring the use of alternate fuels such as coal or oil.

This study analyzes curtailment plans of interstate pipelines, intrastate pipelines and gas distributors, and also analyzes state and federal policy with respect to implementation of these curtailment plans. In light of applicable curtailment plans and available information regarding the supply situations for gas pipelines and distributors, the availability of gas to 415 electric utility power plants is projected annually to 1980. These plants accounted for 93 percent of electric utility gas consumption in the U.S. in 1973. The study appraises the impact of the gas shortage on demand for fuel oil and coal and the fuel burning capability other than gas for electric utilities.

The study is contained in two volumes, one containing text and the second containing schedules. Immediately following this introduction is a summary of pertinent findings. The main body of text begins with the analysis of the jurisdictional aspects of electric utility gas consumption, describing the gas purchases of 415 electric utility power plants. Chapter II describes the curtailment plans of interstate pipelines, and Chapter III explains curtailment policies of companies who do not fall under Federal Power Commission jurisdiction. The forecasts of gas availability for individual power plants are explained in Chapter IV. The study concludes with Chapter V, which deals with the alternative fuel burning capability of electric utilities.

SUMMARY

Until the 1970's, natural gas consumption by electric utilities accounted for a significant and growing proportion of both total natural gas consumption by all users, and of total electric power generated. In the 1970's, however, increasing shortages of natural gas have reversed this trend.

Considerable variations exist in the amount of natural gas burned by electric utilities in various parts of the U.S. and in the sources of this gas. The following table sets out the volumes of natural gas consumed in 1973 by EPA region and by types of supplier. The table is a summary of the results of the analysis of 415 gas-burning power plants which cover 93 percent of the natural gas consumed by electric utilities in the U.S.

Consumption of gas by power plants analyzed herein amounted to 3.4 trillion cubic feet (Tcf) in 1973, of which 1.3 Tcf or 38 percent was sold by interstate pipelines. The remaining 62 percent was sold to electric utilities by intrastate pipelines or gas producers. Interstate pipelines are regulated by the Federal Power Commission, and thus this agency has significant influence on the amount of gas sold directly or indirectly to power plants by interstate pipelines. In gas producing regions, electric utilities can obtain gas from producers or intrastate pipelines, which are subject to

SUMMARY OF ELECTRIC UTILITY PURCHASES OF NATURAL GAS BY TYPE OF SUPPLIER

1973

(Billions of Cubic Feet)

EPA Region	From Interstate Suppliers	From Intrastate Suppliers	From Producers	Other	Total
I	5.6	0	0	0	5.6
II	64.5	0	0	0	64.5
III	4.1	0	0	0	4.1
IV	144.0	0	110.1	0	254.1
V	138.2	0	0	0	138.2
VI	183.3	1,798.3	47.0	1.9	2,030.5
VII	245.3	52.9	3.5	0	301.7
VIII	58.5	3.7	0	0	62.2
IX	447.8	70.8	8.9	0	527.5
X	2.4	0	0	0	2.4
TOTAL	1,293.7	1,925.7	169.5	1.9	3,390.8

EPA Region I - Massachusetts, Rhode Island, Vermont, Connecticut, Maine, New Hampshire
EPA Region II - New Jersey, New York
EPA Region III - Delaware, Pennsylvania, Virginia, Maryland, West Virginia
EPA Region IV - Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee
EPA Region V - Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin
EPA Region VI - Arkansas, Louisiana, New Mexico, Oklahoma, Texas
EPA Region VII - Iowa, Kansas, Missouri, Nebraska
EPA Region VIII - Colorado, Montana, South Dakota, North Dakota, Utah, Wyoming
EPA Region IX - Arizona, California, Nevada
EPA Region X - Oregon, Washington, Idaho

regulation by state regulatory bodies.

Interstate pipelines suppliers accounted for all gas received by power plants in EPA regions I, II, III, V, and X, and the majority of gas in regions VII, VIII and IX. In region IV, the sources of gas to power plants were evenly divided as between interstate and intrastate. In region VI, where a total of 2.0 Tcf, or 60 percent, of total electric utility consumption was burned in power plants, the sources were largely from intrastate pipelines and producers.

Increasing natural gas shortages have necessitated the development of curtailment plans by sellers of gas to deal with their inability to satisfy contractual obligations. The Federal Power Commission has formulated guidelines for interstate pipelines which reflect end-use considerations in determining the reductions in deliveries to customers. Volumes for residential and small commercial use are treated as the highest priority. The next priority is composed of larger commercial users and industrial users, predominantly those with small daily takes or who use gas for purposes which have no alternatives to gas. Larger industrial customers with firm contracts follow in the priority structure. Last in the priority structure are volumes for users with interruptible contracts, with curtailments reflecting size. Volumes for the lowest priority of use are to be completely eliminated prior to curtailment of volumes for the next priority. Since electric utilities served directly or indirectly by interstate pipelines generally purchase relatively large amounts of gas under interruptible contracts, they would be theoretically curtailed first.

Not all interstate pipelines are operating under end-use plans. However, traditional operating practice by gas companies would result in initial curtailments falling first on interruptible contracts. Also, in light of FPC policy it is reasonable to assume that as shortages worsen, virtually all interstate pipelines will have end-use plans in effect. Some variations in the specific priority structure can be expected to accomodate differences in the market structure of various pipelines.

The curtailment policies of local regulatory bodies affect results to ultimate consumers in those cases where gas obtained by distributor companies from interstate pipelines is subsequently resold and where gas flows directly from producers or intrastate customers to ultimate consumers without entering interstate commerce. Electric utility use is generally among the first to be reduced in times of shortfalls in most states for which information is available.

Electric utilities in Texas consume 37 percent of the gas consumed by electric utilities in the U.S. In that state, electric utility boiler fuel use also is considered to be low priority in curtailments. Moreover, the Texas Railroad Commission has initiated hearings to explore the phaseout of natural gas used as a boiler fuel in the state.

It may thus be surmised that electric utilities initially will bear the brunt of the gas shortage in the U.S. The following table summarizes the projections of electric utility gas consumption to 1980 by year.

These projections reflect plant by plant projections developed in this study. As data were available, individual company situations with respect to supply and requirements and curtailment plans in effect were reviewed.

The total volume of natural gas consumed by electric utilities is shown to decline by half between 1973 and 1980. In EPA regions I, II, III and V, it is projected to be virtually non-existent in the late 1970's.

By 1980, it is projected that within predominantly interstate markets electric utilities in only two states -- Kansas and Florida -- will have appreciable gas consumption. Nevertheless, electric utility gas consumption in both states is forecast to decline significantly. California, New York and Arkansas, three states in which electric utilities have traditionally burned large amounts of gas, would have little gas available for electric utility gas consumption after 1975. Thus, for predominantly interstate markets, it may be concluded that gas will not be a major boiler fuel in the future.

SUMMARY OF CURRENT AND PROJECTED GAS CONSUMPTION FOR ELECTRIC UTILITY STEAM GENERATING PLANTS

1973 - 1980
(Trillions of Btu's)

EPA Region	1973	1974	1975	1976	1977	1978	1979	1980
EPA Region I	5.7	7.7	5.5	2.8	0	0	0	0
EPA Region II	66.4	39.5	27.2	6.6	3.9	.4	0	0
EPA Region III	2.2	2.9	.6	0	0	0	0	0
EPA Region IV	259.9	236.0	183.3	143.8	129.7	127.6	103.3	79.6
EPA Region V	131.5	147.8	89.9	20.4	6.6	3.4	0	0
EPA Region VI	2053.2	2095.1	1938.3	1815.3	1752.0	1702.6	1645.0	1590.7
EPA Region VII	298.9	283.9	249.0	82.6	52.4	46.9	42.1	37.3
EPA Region VIII	55.6	61.8	49.9	27.3	21.5	18.0	15.2	12.8
EPA Region IX	560.2	376.7	171.4	22.8	21.5	20.6	20.1	19.5
EPA Region X	2.5	.9	1.5	1.5	1.5	1.5	1.5	1.5
Total United States	3436.1	3252.3	2716.6	2123.1	1989.1	1921.0	1827.2	1741.4

Gas consumption by electric utilities in EPA region VI is shown to decline significantly, but not to the same relative extent as in other regions. Depending on actions by the Texas Railroad Commission and other authorities in this region, this projection could be altered significantly.

The impact of the gas shortage on electric utilities will be to displace a substantial portion of their energy needs to other fuels. Each of the 415 gas-burning power plants has been analyzed, based upon available data, to determine its capability to burn alternate fuels. With the major exception of plants in EPA region VI, most of the electric utilities in the U.S. are capable of burning oil or coal in gas-burning plants with little or no boiler derating.

The alternate fuel capability of gas-burning electric utilities in EPA region VI is difficult to assess. In 1973, the majority of plants had limited or no alternate fuel capability. Since 1973, some plants have been modified so as to be able to burn alternate fuels, and some electric utilities indicate future plans for plant modification. However, the exact number of plants which have undergone or will undergo conversion cannot be estimated at this time.

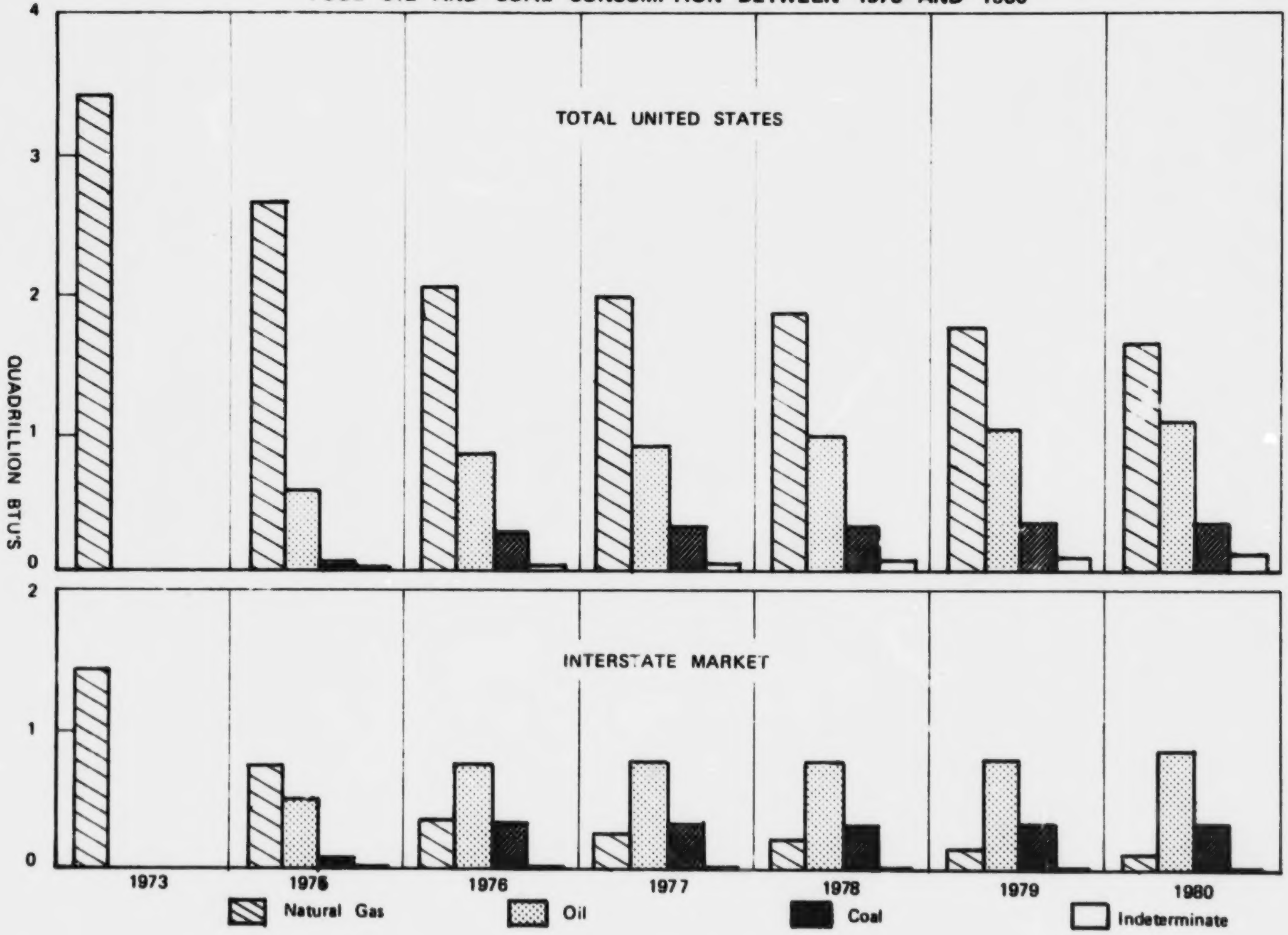
By integrating the plant by plant projections of natural gas availability with the plant by plant analysis of alternate fuel capability, the effect of the gas shortfall on alternative fuel consumption can be estimated. The following chart and table show the estimated use of alternative fuels by existing electric utility plants due to reductions in gas supply from 1973 to 1980. The declines in gas consumption effect changes in one of three categories -- demand for coal, demand for oil and indeterminate (limited or no known alternative fuel burning capability at this time).

It should be noted that on the table certain data are shown in brackets, denoting negatives. This situation arises for plants in which gas consumption is projected to increase from 1973 levels and therefore the consumption of alternative fuels would decline.

By 1980, shortfalls in gas deliveries in the U.S. would result in additional coal consumption of over 348 trillion Btu's and additional fuel oil consumption of 1074 trillion Btu's. A net reduction of 273 trillion Btu's is shown for plants which at this time have limited or no known alternative fuel burning capability. Excluding those plants for which increases in gas consumption are projected, the reduction in gas deliveries by 1980 would be 349 trillion Btu's in plants which at this time have limited or no known alternative fuel burning capability.

Most of the indeterminate category is within EPA region VI. Based upon the conversions of gas-fired plants to oil which have already taken place, it might be assumed that to the extent conversion is feasible, the most likely alternative in this region is fuel oil.

PROJECTED DECLINE IN NATURAL GAS CONSUMPTION BY ELECTRIC UTILITIES AND THE RESULTING INCREASES IN FUEL OIL AND COAL CONSUMPTION BETWEEN 1973 AND 1980



PROJECTED INCREASES IN FUEL OIL AND COAL CONSUMPTION BY ELECTRIC UTILITIES ATTRIBUTABLE TO THE DECLINE IN NATURAL GAS CONSUMPTION BETWEEN 1973 AND 1980

(Trillions of Btu's)

EPA Region	1973 Gas Consumption	Demand Displaced to Other Fuels Due to Reductions in 1973 Gas Volumes[a/] [b/]																	
		1975			1976			1977			1978			1979			1980		
		Coal	Oil	Indeterminate	Coal	Oil	Indeterminate	Coal	Oil	Indeterminate	Coal	Oil	Indeterminate	Coal	Oil	Indeterminate	Coal	Oil	Indeterminate
I	5.7	-	0.2	-	0.5	2.5	-	0.5	5.2	-	0.5	5.2	-	0.5	5.2	-	0.5	5.2	-
II	66.4	5.7	33.6	-	8.5	51.2	-	8.7	53.8	-	8.9	57.0	-	8.9	57.4	-	8.9	57.4	-
III	2.2	0.9	0.7	-	1.4	0.8	-	1.4	0.8	-	1.4	0.8	-	1.4	0.8	-	1.4	0.8	-
IV	259.9	38.9	37.6	-	59.3	56.8	-	61.4	68.8	-	61.5	70.7	-	61.5	95.0	-	61.5	118.7	-
V	131.5	30.5	7.0	4.2	66.7	34.2	10.3	78.6	35.8	10.7	80.2	37.4	10.7	81.8	39.1	10.7	81.8	39.1	10.7
VI	2053.2	(2.3)	94.6	23.5	(2.3)	159.1	81.0	(2.3)	183.0	120.5	(2.4)	190.4	162.6	(2.4)	197.5	213.1	(2.4)	204.2	260.7
VII	298.9	21.7	29.5	(1.1)	131.6	85.9	(0.8)	155.1	92.4	(0.6)	155.1	97.6	(0.3)	155.1	102.2	(0.1)	155.1	106.8	0.1
VIII	55.6	2.9	2.1	0.9	22.0	5.4	0.9	26.8	6.3	1.0	30.1	6.5	1.0	32.7	6.7	1.1	35.0	6.8	1.1
IX	560.2	5.3	383.4	-	6.5	530.6	-	6.5	531.9	-	6.5	532.9	-	6.5	533.3	-	6.5	533.9	-
X	2.5	-	1.0	-	-	1.0	-	-	1.0	-	-	1.0	-	-	1.0	-	-	1.0	-
Total	3436.1	103.6	589.7	27.5	294.2	927.5	91.4	336.7	979.0	131.6	341.8	999.5	174.0	346.0	1038.2	224.8	348.3	1073.9	272.6

a/ Excludes allowance for increases in generation. The total of coal, oil, and indeterminate would equal the reduction in gas volume from the 1973 base period. The estimates for coal and oil reflect only known capability to burn alternate fuels.

b/ No adjustment for thermal efficiency.

c/ Brackets denote increases in gas consumption from 1973 levels which would correspondingly reduce alternative fuel consumption.

d/ Negligible

The table on the following page shows the same data for fuel oil and coal in barrels and tons, respectively. In 1980 the reduction in gas consumed by electric utilities in the U.S. would result in consumption of 170.8 million barrels of oil and 15 million tons of coal.

PROJECTED INCREASES IN FUEL OIL AND COAL CONSUMPTION BY ELECTRIC UTILITIES ATTRIBUTABLE TO THE DECLINE IN NATURAL GAS CONSUMPTION BETWEEN 1973 AND 1980

	Demand Displaced to Other Fuels Due to Reduction in 1973 Gas Volumes[a/] [b/]											
	1975		1976		1977		1978		1979		1980	
EPA REGION	Fuel Oil (000 Bbls.)	Coal (000 Tons)	Fuel Oil (000 Bbls.)	Coal (000 Tons)	Fuel Oil (000 Bbls.)	Coal (000 Tons)	Fuel Oil (000 Bbls.)	Coal (000 Tons)	Fuel Oil (000 Bbls.)	Coal (000 Tons)	Fuel Oil (000 Bbls.)	Coal (000 Tons)
I	32	-	398	22	827	22	827	22	827	22	827	22
II	5,344	246	8,144	366	8,558	375	9,066	384	9.130	384	9,130	384
III	111	39	127	60	127	60	127	60	127	60	127	60
IV	5,981	1,677	9,034	2,556	10,943	2,647	11,245	2,651	15,111	2,651	18,080	2,651
V	1,114	1,315	5,440	2,875	5,694	3,388	5,949	3,457	6,219	3,526	6,219	3,526
VI	15,047	(99)	25,306	(99)	29,108	(99)	30,285	(103)	31,414	(103)	32,480	(103)
VII	4,692	935	13,663	5,673	14,697	6,685	15,524	6,685	16,256	6,685	16,987	6,685
VIII	334	125	859	948	1,002	1,155	1,034	1,297	1,066	1,409	1,082	1,508
IX	60,983	228	84,397	280	84,604	280	84,763	280	84,826	280	84,922	280
X	159	-	159	-	159	-	159	-	159	-	159	-
Total	93,797	4,466	147,527	12,681	155,719	14,513	158,979	14,733	165,135	14,914	170,013	15,013

a/ Excludes allowance for increases in generation. The total of coal, oil, and indeterminate (not shown) would make up for the loss in output caused by reductions in gas volumes from 1973 base period. The estimates for coal and oil reflect only known capability to burn alternate fuels.

b/ No adjustment for thermal efficiency.

Source: Summary Schedule page xi; Btu's converted to barrels of oil and tons of coal according to average Btu contents as reported by U. S. Bureau of Mines: Residual Fuel Oil - 149,690 Btu/gal., Utility Coal - 11,600 Btu/lb.

CHAPTER I

CONSUMPTION OF GAS BY ELECTRIC UTILITIES

Until 1973, increasing quantities of natural gas had been consumed annually by electric utilities in the U.S. Moreover, an increasing share of total electric output had been generated by consumption of natural gas up through 1970. These trends have been reversed in the last two years, as shown on the table below.

Year	Natural Gas Consumption in Power Plants		Electric Output From Natural Gas Consumed	
	Trillion Btu	Percent of Total Gas Consumption	Million kwh	Percent of Total Electric Output
1966	2,536	14.2%	251,151	26.5%
1968	3,081	15.0	304,433	27.5
1970	3,920	16.8	372,884	29.1
1972	4,271	17.2	375,682	25.5
1973	3,651	17.1	336,001	21.3

Source: Future Requirements Committee, Edison Electric Institute.

The proportion of total electric output attributable to consumption of natural gas began to decline in 1971 despite continuing increases in total gas volumes, largely because of sharp increases in electric generation with nuclear fuel and fuel oil. The trend towards a declining electric output share of natural gas will almost certainly accelerate in the future as the sharpening natural gas shortage makes further inroads into supplies of gas available to electric utilities.

The focal point of this study is to analyze the availability of natural gas to electric utility steam-electric plants. Major variables affecting gas consumption are the total amount of gas available for all users and the methods of allocating limited supplies among classes of service -- residential, commercial, industrial, and electric utility -- by the sellers of gas. The purpose of this chapter is to set the stage for subsequent analyses by establishing general gas supply and demand considerations which affect electric utility gas consumption, identifying the gas burning power plants that are studied, and analyzing the sources of gas supply to these power plants.

A. Natural Gas Supply and Demand

There is a critical and continuing shortage of natural gas in the United States. Natural gas has been a major source of energy in the United States since World War II, and has become the "premium" fossil fuel for energy consumption in the United States. From 1960 to 1973, consumption of gas increased 86 percent, substantially more than consumption of coal and petroleum, but substantially less than the increase which would have taken place but for the gas shortage that developed in the latter part of this period.

There are two major reasons accounting for the substantial increase in demand for gas -- its unique physical characteristics vis-a-vis other fossil fuels and its low price. The popularity of gas in part reflects its clean-burning characteristics and the convenience of its use. Since the sulfur content of gas is negligible at the burner tip, gas does not foul or corrode the equipment in which it is burned to the extent that coal and oil do. The clean-burning characteristics of gas have taken on added importance in recent years because the United States has undertaken a substantial effort to reduce air pollution. Users of gas do not require on-site storage facilities which are required for oil and coal. Also, natural gas has certain physical attributes which make it desirable for use in direct-firing applications or as a raw material in the chemical industry.

However, the magnitude of the shortage indicates that not all demands can be met for the indefinite future, and indeed at the present time current contracts to deliver specified volumes of gas to consumers cannot be fulfilled due to lack of supply. Interstate pipelines curtailed firm contracts by 1968 billion cubic feet (Bcf) in 1974.

Increasing curtailments by pipelines reflect declining deliverability of natural gas reservoirs, caused by reserves additions1/ inadequate to support increased levels of

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1/ The term reserves additions means the annual net change in proved reserves, reflecting discoveries of new fields, new reservoirs in old fields, extensions, and revisions of prior estimates.

production. Proved reserves[1] of natural gas have been falling since 1968, declining to 205 trillion cubic feet at the end of 1974. From 1968 to 1974, reserves additions have been less than half of production. The natural gas reserves-to-production ratio for the Lower 48 States has fallen from 21.8 in 1956 to 15.8 in 1967 to 9.7 in 1973 and 1974. In 1974, production declined by 5.8 percent, the first recorded production decline since a small downward change in 1958.

B. Gas Consumption by Sector

Gas consumption by sector -- residential, commercial, industrial and electric utility -- is set out on Schedule I-1 as reported by the Future Requirements Committee. Sheets 1 and 2 of the schedule show consumption of gas in trillions of Btu's by region[2] and state, and sheets 3 and 4 show the percentage distribution of gas consumption by sector for each region and state.

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[1] Proved reserves are the current estimated quantity of natural gas which analyses of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known gas reservoirs under existing operating and economic conditions. Thus, proved reserves differ from the potential reserves which have not as yet been found.

[2] The regional designations utilized in the main body of text hereinafter are those of the Future Requirements Committee.

In 1973, gas consumption in the Lower 48 United States was 19,876 trillion Btu's, excluding field and "other" use. Of this total, firm[1] residential and commercial customers consumed 36.4 percent, firm industrial customers consumed 31.3 percent, interruptible[2] industrial customers consumed 13.9 percent, firm electric utility customers consumed 10.6 percent and interruptible electric utility customers consumed 7.8 percent.

The distribution of gas consumption varies considerably by region and state. At one extreme, over three-quarters of the gas market in New England is comprised of residential and commercial customers. Conversely, less than 11 percent of the gas market in the Gulf Coast is comprised of residential and commercial customers -- the preponderance of consumption is comprised of industrial and electric utility fuel users.

Approximately two-thirds of industrial gas consumption in the Lower 48 States occurs in eight states, which are listed below.

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[1] Service offered to customers under schedules or contracts which anticipate no interruptions. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened.

[2] Low priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the claim of firm service customers and high priority users.

INDUSTRIAL GAS CONSUMPTION BY STATE

1973

	Trillions of Btu's	Percent of National Total
Texas	2162	24.0%
Louisiana	1120	12.4
California	702	7.8
Ohio	437	4.9
Illinois	378	4.2
Pennsylvania	375	4.2
Michigan	356	4.0
Indiana	282	3.1
All Other States	3182	35.4
Total	8994	100.0

Source: Future Requirements Committee.

The volume of industrial gas consumed in Texas, Louisiana, and California reflects not only the overall dimension of industrial energy requirements in these states but also the heavy reliance on gas to meet industrial energy requirements -- in 1973 gas met 83 percent of California industrial energy consumption, and over 90 percent of industrial energy consumption in Texas and Louisiana.

In each of the 8 largest industrial gas consuming states with the important exception of California, firm contracts dominate industrial consumption. Firm volumes range from 67 percent of industrial gas consumption in Michigan to 97 percent in Louisiana. However, in California firm gas is only 14 percent of total industrial gas consumption, reflecting California policy of not allowing firm industrial contracts over 200 Mcf/day.

The remaining states, those with smaller volumes of industrial gas consumption, rely upon interruptible contracts to a greater degree. The distribution of firm versus interruptible volumes, although varying somewhat in degree for specific states, is approximately 50-50.

The following table shows electric utility gas consumption in eight states which comprised 82 percent of electric utility gas consumption in 1973.

ELECTRIC UTILITY GAS CONSUMPTION BY STATE

1973

	Trillions of Btu's	Percent of National Total
Texas	1285	37.4%
California	468	13.6
Louisiana	387	11.3
Oklahoma	267	7.8
Kansas	156	4.5
Florida	148	4.3
Arkansas	49	1.4
New York	48	1.4
All Other States	628	18.3
Total	3436	100.0

Source: Form 423's accounting for 93 percent of total reported electric utility gas consumption.

Thus, gas consumption by electric utilities is somewhat more concentrated in a few states than gas consumption by industrials. Some 37 percent of electric utility gas consumption occurs in the state of Texas alone. There are 9 contiguous states which have no or negligible consumption of gas by electric utilities. Moreover, it is interesting to note that five of the eight largest industrial gas burning states -- Ohio, Illinois, Pennsylvania, Michigan and Indiana are not among the above listing of the eight largest electric utility gas consuming states.

In Texas, Louisiana, Oklahoma, and Florida, firm gas consumption accounts for 75 to 100 percent of total electric utility gas consumption. In California, Kansas, Arkansas and New York firm volumes are of little or no relative importance. Generally, most electric utilities in other states[1] rely largely on interruptible gas.

C. Sources of Gas Supply to Electric Utilities

This section explores in greater detail the flow of gas to electric utilities in the Lower 48 States. By reference to data developed for each of 415 gas burning electric utility steam electric plants, this section identifies some key contractual provisions with respect to gas purchases by electric utilities. In addition, the sources (suppliers) of gas to these specific electric utilities are traced.

The Environmental Protection Agency provided a list of power plants which burned gas from 1969 to 1973. some of which did not burn gas in 1973 or in prior years. To develop the list of gas burning steam electric plants utilized herein, some plants which did not burn gas in prior years were included. Gas burning plants which began operation after 1973 where added as well as some small gas burning plants with nameplate ratings less than 25 Mw.

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[1] Nevada and New Mexico are significant exceptions in that electric utilities in these states burn greater amounts of firm gas than interruptible gas.

The plants utilized herein burned 93 percent of reported electric utility gas consumption in 1973, which includes some gas turbine use. It is believed that the remaining 7 percent would be accounted for in gas turbine use, small plants, or synthetic (refinery or blast furnace) gas.

Schedule I-2 shows for 415 gas burning power plants the volume of firm or interruptible gas consumed in 1973 and whether or not the gas contract expires within 24 months, as of December 1974 by supplier. The notes (column 8) indicate changes which may have occurred in 1974 with respect to the gas contracts, and other pertinent observations.

The total natural gas purchases shown at column (4) were provided by the Environmental Protection Agency, except as noted. The volumes attributable to firm and interruptible contracts and individual suppliers were estimated by reference to FPC Form 423 data.

Column (5) shows the percent of gas consumption by the power plant provided by the supplier indicated at column (7). For example, the gas consumed by the Kendall Square Plant in Massachusetts (sheet 1) burned 500 MMcf of interruptible gas in 1973, all of which was supplied by Commonwealth Gas Co., which in turn buys gas from Algonquin Gas Transmission, an interstate pipeline.

The second power plant shown on sheet 1 is the Fitchburg plant, which burned 596 MMcf of interruptible gas in 1973 representing an interdepartmental transfer. Interdepartmental gas transfers often occur for combination electric and gas utilities, whereby the electric department purchases gas from the gas department. In the case of Fitchburg Gas and Electric, the gas department purchases gas from Tennessee Gas Pipeline Co., an interstate pipeline. Thus, the company (ies) that actually sells (sell) the gas is the first listed, and the company (ies) shown in parentheses is the next link in the transfer of gas.

The detailed information provided with respect to the sources of gas supply to the electric utilities is critical in determining the future volume of gas available to these electric utilities, as the supply situation and type of curtailment plan of the supplier will influence the amount of gas to the power plants. Moreover, whether or not the gas supply moves through interstate commerce subject to tariff regulation of the Federal Power Commission (FPC) is an important consideration. As discussed at length in Chapter II, the FPC and pipelines operating under its jurisdiction have developed curtailment plans which affect the amount of gas that electric utilities will burn. Thus, the denotation "interstate" following a pipeline's name indicates that it falls under tariff jurisdiction of the

FPC. Some pipelines, or gas transportation contracts, although subject to certificate jurisdiction of the FPC, are shown as intrastate because they do not fall under FPC tariff jurisdiction. A substantial number of electric utilities in gas producing states receive gas from intrastate companies whose gas supply and transportation facilities are entirely intrastate and these are indicated as intrastate on the schedule.

Schedule I-3 summarizes by state some of the data from I-2, showing electric utility purchases of natural gas by type of supplier. For example, columns (1), (2) and (3) show gas burned by electric utilities which passes through interstate pipelines subject to tariff regulation of the FPC. Column (1) indicates interdepartmental transfers, column (2) indicates direct purchases from interstate pipelines, and column (3) shows purchases from intrastate pipelines or distributors who in turn purchase gas from interstate pipelines. Columns (4), (5) and (6) show purchases of gas by electric utilities from intrastate pipelines which do not pass through interstate pipelines subject to tariff regulation of the FPC.1/ Column (7) shows the amount of gas which is purchased by electric utilities directly from producers, without transfer of ownership to a distributor and/or pipeline.

1/ Column (6) shows purchases from intrastate pipelines or distributors who in turn acquire their gas from other intrastate pipelines.

Schedule I-3 shows that for the total U.S., electric utilities directly or indirectly purchased 1294 Bcf from interstate pipelines, 1926 Bcf from intrastate pipelines, and 170 Bcf from producers. Of the volume purchased from interstate pipelines 28 percent was transferred from the gas departments of combination utilities, 34 percent was purchased directly from interstate pipelines, and 38 percent was purchased from intrastate pipelines or distributors who in turn purchased the gas from interstate pipelines. With respect to the gas consumed by electric utilities which is not affected by FPC jurisdiction, the majority - 95 percent - is purchased from intrastate pipelines who in turn buy the gas at the wellhead in those states.

Schedule I-3 also facilitates analysis of sources of gas supply to electric utilities for specific regions and states. Electric utilities in the New England and Appalachian regions acquire all of their gas through interstate pipelines, which generally flows to the power plants via interdepartmental transfers.

In the Southeast region, less than half of electric utility gas consumption is purchased from interstate pipelines, with the remainder indicated as being purchased from producers. Florida Power and Florida Power & Light purchase gas from producers in Louisiana and Texas which is then transported to power plants in Florida by Florida Gas Transmission, an interstate pipeline. While these transportation arrangements were subject to FPC approval, it is believed that the volume of gas transported is not curtailable[1] as are the actual sales to power plants by Florida Gas Transmission.

In the Great Lakes and Northern Plains regions, all of the gas consumed by electric utilities flows through interstate pipelines. Approximately 24 Bcf is purchased directly from interstate pipelines, 82 Bcf represents interdepartmental transfers and 124 Bcf is purchased from gas distributors who in turn buy from interstate pipelines.

States in the Mid-Continent and Gulf Coast regions generally burn more gas in power plants than those in other regions previously discussed. The Mid-Continent and Gulf Coast regions contain most of the gas produced in the U.S., and thus it is not surprising that electric utilities burn large volumes of gas from intrastate sources. In this region, only in Missouri and Mississippi do electric utilities purchase all their gas via interstate pipelines. Electric utilities in Kansas purchased 63.9 percent of their gas from interstate pipelines, the remainder coming from intrastate sources. Interstate pipelines provided 92 percent of electric utility gas consumption in Arkansas.

The states of Oklahoma, Louisiana, and Texas are characterized by large volumes of gas moving to power plants

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1/ Except to the extent that pipeline capacity is unavailable.

without passing through FPC jurisdiction. In Oklahoma 99 percent of the 271 Bcf burned by electric utilities was purchased from intrastate pipelines. Electric utilities in Louisiana burned 369 Bcf of gas in 1973, of which 28 percent came from interstate pipelines.

Texas utilities burn 37 percent of the gas consumed by electric utilities in the U.S., and less than 2 percent of this gas is evidently subject to curtailment by interstate pipelines. Virtually all of the electric utility gas in Texas is sold through gas companies subject to Texas Railroad Commission regulation.

Electric utilities in New Mexico acquire over half of their gas from intrastate sources. However, total electric utilities in this state burned but 64 Bcf of gas in 1973.

Thus, for purposes herein, the states of Texas, Louisiana, Oklahoma and New Mexico are treated as predominantly intrastate markets. The remaining states are treated as predominantly interstate markets.

Chapter II discusses the curtailment policies of interstate pipelines which will affect the gas available to the electric utilities they serve. Chapter III discusses state policies towards the allocation of gas in times of shortage.

CHAPTER II

CURTAILMENTS OF NATURAL GAS SALES BY INTERSTATE PIPELINE COMPANIES

Curtailments of natural gas service by interstate pipelines, reducing in part or entirely deliveries of gas on certain days to selected classes of customers, and the resulting similar curtailments by their local gas distributor customers are not new events in gas pipeline history. Since the early days of the industry, the 1930's, service curtailments have been employed to achieve the maximum economic results from the large dollar investment in pipeline capacity. These curtailments may be designated as capacity curtailments -- reductions in deliveries to certain customers (generally authorized under contract) when pipeline capacity is being fully utilized to serve other customers. Until 1968, gas supply was not a problem. In recent years, steadily diminishing supplies of natural gas have resulted in the need for reduction in deliveries due to insufficient overall supply rather than lack of pipeline capacity.

The history of pipeline and gas distributor service curtailments starts in the 1940-1950 decade when the great expansion of the natural gas industry began. The industry grew from a supplier of 14 percent of the national energy requirements in 1947 to 33 percent in 1970.

This chapter initially deals with traditional gas pipeline economics which significantly influence the design of pipeline curtailment plans. Following this overview of the gas pipeline industry is an analysis of overall Federal Power Commission policy towards pipeline curtailments. This chapter concludes with a summary of the effective curtailment plans for 38 interstate pipeline companies and the impact of these plans on the availability of gas for industrial and electric utility use.

A. Traditional Gas Pipeline Economics

Most of the discussion that follows has equal application to both the interstate pipelines and their local gas distribution customers. The most recent annual sales statistics, for 1973, report that sales for resale by the major pipelines to gas distributors comprised 90 percent of total pipeline sales.

In general, the pipelines and their distributor customers supply two kinds of service: firm or guaranteed service available on demand on any day, and interruptible or curtailable service available on days when firm gas requirements are less than capacity in the case of pipelines, and less than the total gas supplies the local distributor can call upon. Pipeline capacity is designed and constructed to equal or slightly exceed the estimated peak day requirements for firm service.

Before capacity curtailments became a normal procedure in pipeline operations and equitable plans for curtailment of service were instituted and enforced, there were problems similar to those recently arising as curtailments of deliveries due to gas supply shortages.

An illustration of pipeline capacity curtailments during the early development period of the industry and the problems arising from refusal of some interruptible service customers to obey curtailment orders is provided in the following comment on page 270 of the report on the Natural Gas Investigation 1944-1946 (Gas Investigation Report):[1]

> "It seems reasonable to expect that recent experiences with drastic curtailments and the resulting chaotic conditions of service may have contributed to a better understanding of this situation on the part of both the supplying companies and their interruptible customers."

The "drastic curtailments and chaotic conditions of service" referred to in the Gas Investigation Report led to adoption of restrictions in the late 1940's on addition of residential and commercial space heating customers in a number of the gas consuming states. The restrictions were imposed by the state regulatory commissions on the local gas distributing companies until the capacity of the supplying pipelines under construction (new pipelines or expansion of existing pipelines) would be sufficient to meet winter heating requirements. Rapid development of the interstate pipeline industry in the 1945-1955 decade permitted state imposed restrictions to be lifted and the addition of space heating loads to be controlled in an orderly pattern under the construction authorization granted to the expanding interstate pipeline industry by the Federal Power Commission.

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[1] Natural Gas Investigation, Docket No. G-580, Federal Power Commission, Report of Commissioner Nelson Lee Smith and Commissioner Harrington Wimberly transmitted to Congress April 28, 1948.

The capacity curtailment experience of the pipelines during the early stages of the pipeline industry was influenced by the following factors:

a) The nature of pipeline service

b) Economics of pipeline operation

c) Characteristics of demands for natural gas

d) Regulation of pipelines under the Natural Gas Act, as it applied to rates, tariffs service rules and construction authorizations.

Pipeline Services

Interstate pipelines sell for resale -- wholesale sales -- (1) to local gas distributors for their retail sales to residential, commercial, industrial and governmental consumers, and (2) to other interstate pipelines for resale to local gas distributors and for retail sales to industrial, commercial and governmental consumers. Pipelines also sell gas (depending upon sales policies) at retail to industrial and governmental customers located adjacent to the pipeline system -- main line industrial customers. In addition, pipelines, if capacity is available, transport over varying distances the gas owned by other pipelines and gas owned by local gas distributors and other parties (e.g., petroleum company gas from the gas fields offshore to onshore and to inland refineries).

Character of Pipeline Service

In general, an interstate pipeline offers only two qualities of service as defined [1] below for its sales and transportation of gas:

Firm Service

Service offered to customers (regardless of Class of Service) under schedules or contracts which anticipate no interruptions of service. Certain firm service contracts may contain clauses which permit unexpected interruption in event the supply to residential customers is threatened during an emergency.

Interruptible Service

Low priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the claim of firm service customers and higher priority users.[2]

Sales for resale to gas distributors and other pipelines include both firm and interruptible service under,

[1] Adapted from 1973 Gas Facts, Appendix A Glossary; American Gas Association, Department of Statistics.

[2] Refers to temporary sales of short duration to alleviate an emergency and preferred interruptible sales, which take precedence over other interruptible sales if service is curtailed.

in most instances, separate sales contracts. Transportation of gas for others and main line industrial sales may be firm or interruptible or a combination of both methods; e.g., firm service up to a specified daily volume and any additional daily volumes subject to interruption.

Economics of Pipeline Operation

Interruptible sales are made at lower prices than those which apply to firm sales to compensate for the lower priority of service during peak gas demands on the pipeline capacity. The usual interruptible sales contract requires that the customer maintain a reasonable supply of other fuel for heat requirements during periods of gas curtailment.

The definition of firm and interruptible pipeline services applies also to the same kind of services rendered by local gas distributors.

The economics of natural gas transportation (as well as distribution) is importantly influenced by the high degree of capital intensiveness characteristic of the industry. Reflecting the relatively large investment in plant per unit of sales, a large proportion of the overall annual costs of a pipeline are fixed costs. Thus, the volume of throughput for a pipeline has a significant impact on unit costs. Also, it is generally accepted that per unit transportation costs decline when the diameter of the pipe increases.

The primary elements involved in the plant investment of a gas pipeline are pipe and compression. The predominant diameter of all main transmission pipelines was 30-inch in 1972 according to Commission reports. As reported in 1974, the cost per mile of pipeline was $100,000 for 24-inch pipe and $200,000 for 30-inch pipe. Compressor station costs reported in 1974 averaged $302 per horsepower.

The following table shows the three major components of the price of gas paid by consumers in 1973.

Components of the Burner Tip Price of Gas in 1973

	¢/MMBtu	Percent of Total
Field Price	21¢	26%
Transportation Cost	25	32
Distribution Cost	33	42
TOTAL	79¢	100%

Source: American Gas Association, Gas Facts.

Distribution costs comprise the largest portion of the overall price of gas paid by the ultimate consumer, followed by transportation costs. Among final consumers of gas, there is considerable diversity by consuming sector in the prices paid -- residential consumers paid on the average in 1973 125¢/MMBtu compared with 50¢/MMBtu for industrial consumers, including electric utilities.

There is not nearly this price diversity for most of the sales made by pipelines, primarily because their sales are predominantly high load factor[1] sales to distributors or large industrial plants.

Nearly three-fourths of the transportation cost reflects capital items -- taxes, depreciation, interest, and net income. With respect to distribution costs, approximately 60 percent represent capital items.

The design of pipeline rates in part reflects the large proportion of fixed costs associated with transportation. Most pipelines utilize a two-part monthly demand and commodity tariff for their firm service sales for resale to gas distributors.

The demand-commodity rate, also known as the "contract demand" rate, provides the lowest average rate to the local utility customer for monthly purchases at 100 percent load factor (i.e., sales to the customer are made at his maximum daily contract demand on each day of the month). The average rate increases as the customer's monthly load factor decreases.

An illustrative gas pipeline demand-commodity rate and the effect of the monthly load factor on average rate are shown on the following page.

[1] Generally refers to the relationship between average (day or month) sales to peak (day or month) sales. In the following section, load factor and the nature of the gas market are elaborated upon.

Monthly Rate Per Mcf:

Demand	$ 3.04 x Billing Demand
Commodity	30.4¢ x Total Volume of Gas Purchased

Minimum Bill:

The monthly demand charge

Billing Demand.

The contract demand (Maximum Mcf entitlement per day)

Average Monthly Rate Per Mcf:

Load Factor	Average Rate Per Mcf Demand	 Commodity	 Total
100%	10¢	30.4¢	40.4¢
75	13.3	30.4	43.7
50	20	30.4	50.4
25	40	30.4	70.4

The first part of the demand-commodity rate, the demand rate, is often a fixed rate -- the same for all months -- applied to the billing demand which in most cases is the maximum daily volume (24 hour volume) the customer is entitled to receive and the pipeline is required to deliver on demand. The maximum volume is called the contract demand and is measured in units of 1,000 cubic feet (Mcf). The monthly demand rate approximates one-twelfth of the allocated annual demand costs which are composed of a portion of the annual fixed costs of the pipeline. Fixed costs consist of the investment costs, amortization, depreciation and depletion taxes and return on investment in facilities and any operating expenses that do not vary with month to month sales volumes.

The commodity rate consists of the remaining portion of the annual fixed costs plus all variable costs such as cost of gas purchased from producers and other operating expenses that vary with month to month sales. It is applied to monthly sales volumes measured in Mcf.

The minimum monthly bill is usually only the total demand charge (rate x billing demand) but in some instances may require a commodity charge in addition to the demand charge, equal to monthly purchases at 60 to 90 percent load factor.

The cost classification and allocation to determine the demand and commodity costs is based upon a "test year" - a 12-month period reflecting actual experience and known future sales and costs. In pipeline rate cases Commission approval is required of the final classifications and allocations whether or not the rates are determined by public hearing or by informal settlement agreements between the pipeline, the customers and other intervenors, and the Commission's staff.

In the early 1950's, the Commission in a pipeline rate case of the Atlantic Seaboard Gas Company adopted a cost classification and allocation that has remained a standard for the pipeline industry and is known as the Atlantic Seaboard Allocation. In general, pipelines have been required to classify and allocate costs in accordance with the Atlantic Seaboard procedure. Demand and commodity rates could depart from the allocated costs if good cause were shown --- such as loss of large firm industrial loads by the local gas utility customers to a competitive fuel supply. The principal feature of the Atlantic Seaboard cost allocation was the classification of fixed costs -- 50 percent to demand costs and 50 percent to commodity costs.

The 50-50 classification tended to reduce demand rates and increase commodity rates since in prior years most fixed costs had been classified by utilities as demand costs, especially in the electric utility industry for large commercial and industrial sales. The underlying theory for the demand-commodity rate form contemplated that all fixed costs would be recovered by the fixed monthly demand rate and only variable costs would be assigned to the commodity rate. The increase in commodity rates by the Seaboard classification resulted in greater costs being assigned to interruptible service with consequent higher rates to both main line industrial customers of the pipelines and interruptible industrial customers of the local gas utilities. The local gas utilities as a policy, have used the commodity rate charged for gas purchased from the pipeline supplier as the base on which to construct rates for industrial customers receiving interruptible service.

In the past two years, 1973 and 1974, because of the gas supply shortage the Commission has been requiring that the demand and commodity rates level be not less than the costs obtained under the Seaboard classification -- a reversal of previous tolerance of departures. Also, there have been indications that the Commission may require 75 percent instead of 50 percent of the fixed costs to be assigned to commodity costs and to commodity rates. The purpose is to raise the level of interruptible industrial rates, pipeline and distributor, so as to approach the prices of the alternative fuels, oil and coal.

Sales of gas by the interstate pipeline supplier to the local gas distributors for resale are governed by the two key documents filed with and accepted by the Federal Power Commission, and kept up to date by similar filings and acceptance of additions and revisions. The key documents are the effective pipeline tariff and the sales contract or contracts which are designated by the Commission as service agreements. The pipeline company tariff is required to provide a standard form of sales contract for all customers, separately for firm service, interruptible service, and other services, such as storage, winter service, and transportation only of gas.

The sales contract for firm service covering most of the gas sold is also illustrative of the contracts for the other services. Under the standard form, the contract with each firm service customer incorporates by reference to the effective pipeline tariff, (1) the currently effective rate schedule and (2) the General

Terms and Conditions of service which comprise among others, gas quality standards, measurement of gas quantities, meter error adjustments, billing and payment, determination of quantities delivered, e.g., where both firm and interruptible service is purchased through one meter on the same day; and the gas curtailment plans and policies.

Also under the standard form contract but with variations among the customers, are the maximum daily quantities of gas to be delivered (usually designated as the contract demand), the location of delivery points, the pressure of the gas delivered at each point, and the term of service of the sales contract.

The initial contract term of service is almost universally for 20 years. The contract automatically extends from year to year unless advance notice of termination by either party -- usually 12 to 24 months -- has been given. Generally, an addition or reduction in contract demand agreed upon by the parties is implemented by a new 20-year contract for the revised quantity. The pipeline supplier can not discontinue or reduce contract deliveries when the contract terminates without Commission authorization as provided under Section (7) (b) of the Natural Gas Act - Abandonment of Service. (Curtailment of deliveries because of the gas shortage is not subject to Section (7) (b) of the Act as interpreted by the Commission and the courts.)

The gas distributor generally can terminate the contract at the end of the term although the Commission may as a practicable matter prevent termination, in the public interest after hearing, by denying authorization for service to a new supplier.

Characteristics of Demand for Natural Gas

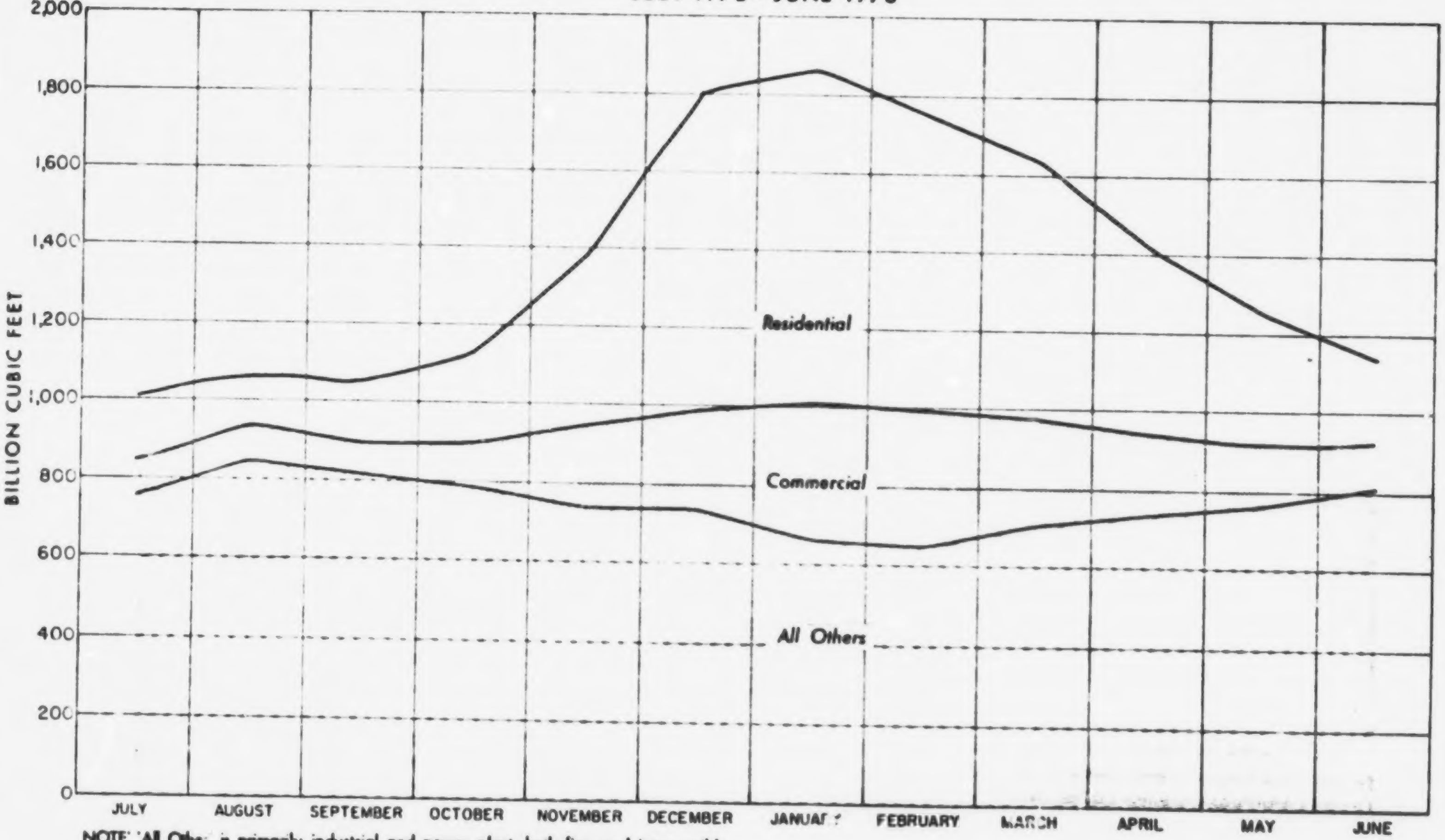
The traditional characteristics of service by pipeline systems reflect in part the nature of distribution economics which are in turn related to the seasonal characteristics of demand for natural gas. Particularly with respect to the relative stability or seasonal fluctuation of demands, it is necessary to distinguish among the classes of use.

The seasonal consumption of gas, both in the composite and for the sectoral distribution, is not uniform throughout the year. Space heating sales, which represent a large proportion of residential and commercial demand, are seasonal in nature, resulting in low-load factors (average day ÷ peak day) for residential and commercial requirements.

On the following page is a chart showing monthly distributor sales of gas in the United States by sector for the year July 1972-June 1973. From this chart the seasonality of residential and commercial sales is quite apparent, with the preponderance of sales occurring in the October to March period. The "All Other" category on the chart is primarily industrial and electric utility, both

MONTHLY DISTRIBUTOR SALES OF GAS IN THE UNITED STATES BY SECTOR

JULY 1972—JUNE 1973



NOTE: 'All Others' is primarily industrial and power plant, both firm and interruptible.

SOURCE: AGA 'Monthly Bulletin of Utility Gas Sales' firm and interruptible. These categories are not separated by the source. However, firm industrial sales generally follow a seasonal pattern similar to residential and commercial sales, although not nearly to the same degree. In part, interruptible sales offset this seasonality by occurring predominantly in the period May to October. The combination of firm and interruptible industrial sales has traditionally resulted in relative seasonal stability for sales to the industrial sectors.

Importantly, interruptible sales also contribute additional revenues to pipelines and distributors without significant additional investment. Due in part to the contribution of these revenues, prices to firm customers have been lower than they would have been otherwise.

By definition and general practice, interruptible sales have been curtailed for many years during periods in which firm demands were high. These were, as has been noted previously, capacity curtailments and considered normal operating procedure.

Regulation Under The Natural Gas Act

Federal regulation under the Natural Gas Act over the interstate pipelines since 1938 and over the sales of gas to them by the gas producers since 1954, has an indirect but important impact on gas curtailments.

The Act which became effective in 1938 delegates the Federal regulation to the Federal Power Commission (Commission) which also regulates interstate movement and sales of electricity. By U.S. Supreme Court decision in 1954 the sales for resale in interstate commerce, i.e., the present and future sales to the interstate pipelines by gas producers, became subject to the Act and regulation by the Commission.

Regulation under the Act is limited to the transportation and sale for resale of gas in interstate commerce.

Retail sales of gas by local gas distributors are regulated by the State Regulatory Commissions. Mainline industrial sales (retail sales) of the interstate pipelines are subject under the Act to the transportation jurisdiction of the Commission but not to its sales and price regulation. Under the Act, licenses for exports and imports of gas to and from foreign countries are under the jurisdiction of the Commission subject to agreement with Commission actions by the Departments of State and Defense.

Sections 4 and 5 of the Act, the "rates and charges" sections, and Section 7, the sales and facilities authorizations section, affect the curtailment of service policies and practices of the interstate pipelines and therefore of the state regulated local gas distributors that are dependent for gas supply on the pipelines.

Under the Act and the Commission's rules and regulations to implement it, the interstate pipelines (natural gas companies) are required (among other requirements) to keep on file with the Commission and to have available at their business offices for public inspection, their rate schedules that are currently in effect. The separate schedules are compiled in a book form designated as the tariff of the company. As noted previously the tariff contains the applicable curtailment plan of the interstate pipeline and other pipeline service provisions.

The purpose of the filing and availability for public inspection is to assure the equal treatment of their customers provided for in Section 4(b) of the Act:

> "No natural gas company shall with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates charges, service, facilities, or in any other respect, either as between localities or as between classes of service."

The following table contains the most pertinent Commission regulations applicable to rate schedules, tariffs and the implementation of Section 4(b).

Selected Regulations and Definitions of the Federal Power Commission Under Section 4 of The Natural Gas Act.

IN GENERAL

§ 154.21 Effective tariff.

The effective tariff of a natural-gas company shall be the tariff filed pursuant to the requirements of this part and permitted by the Commission to become effective. No natural-gas company shall directly or indirectly, demand, charge or collect any rate or charge for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission, or impose any classifications, practices, rules or regulations, different from those prescribed in its effective tariff and executed service agreements on file with the Commission, unless otherwise specifically provided by order of the Commission.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

§ 154.22 Notice requirements.

All tariffs, and contracts or any parts thereof shall be filed with the Commission and posted not less than thirty days nor more than sixty days prior to the proposed effective date thereof unless a different period of time is permitted by the Commission in accordance with § 154.51: *Provided however*, That no natural-gas company shall file under this part any new rate schedule or contract for the performance of any service for which a certificate of public convenience and necessity must be obtained pursuant to section 7(c) of the Natural Gas Act, until such certificate has been issued. Nothing herein shall be construed as preventing the natural-gas company from entering into any such agreement prior to the granting of such a certificate.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

§ 154.23 Acceptance for filing not approval.

The acceptance for filing of any tariff, contract or part thereof is not to be considered as approval by the Commission.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

DEFINITIONS

§ 154.11 Rate schedule.

The term "rate schedule" means a statement of a rate or charge for a particular classification of transportation or sale of natural gas subject to the jurisdiction of the Commission, and all terms, conditions, classifications, practices, rules and regulations affecting such rate or charge. This term also includes any contract for which special permission has been obtained in accordance with § 154.52.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

§ 154.12 Contract.

The term "contract" means any agreement which in any manner affects or relates to rates, charges, classifications, practices, rules, regulations or services for any transportation or sale of natural gas subject to the jurisdiction of the Commission. This term includes an executed service agreement.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

§ 154.13 Service agreement.

The term "service agreement" means an unexecuted form of agreement for service under a natural-gas company's tariff.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

§ 154.14 Tariff or FPC gas tariff.

The term "tariff" or "FPC gas tariff" means a compilation, in book form, of all of the effective rate schedules of a particular natural-gas company, and a copy of each form of service agreement.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

154.15 Filing date.

The term "filing date" means the day on which a tariff or part thereof or a contract is received in the office of the Secretary of the Commission for filing in compliance with the requirements of this part.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

§ 154.16 Posting.

The term "posting" means (a) making a copy of a natural-gas company's tariff and contracts available during regular business hours for public inspection in a convenient form and place at the natural-gas company's offices where business is conducted with affected customers and (b) mailing to each customer affected a copy of such tariff or part thereof at the time it is sent to the Commission for filing.

[Order 144, 13 F.R. 6371, Oct. 30, 1948; 13 F.R. 6838, Nov. 20, 1948]

Source: Regulations Under The Natural Gas Act, Part 154, Federal Power Commission

Regulations especially pertinent to interstate pipeline sales for resale and service curtailments are in Sections 154.21 and 154.11. The prices or rates and the curtailment policies and practices are to be only those in the current tariff. Public and customer inspection of the rate schedules, tariffs and sales contracts is provided in Section 154.16, Posting.

The regulations were instituted in 1948 by the various Commission orders. These no doubt have helped to prevent reoccurrence of the "recent experiences with drastic curtailments and the resulting chaotic conditions of service" referred to in the Gas Investigation Report.

Many recent FPC curtailment hearings have been instigated when the pipelines filed their curtailment plans pursuant to Section 4 of the Act and the Commission's regulations.

Mainline industrial sales of the pipelines, firm and interruptible, are not covered by the regulations quoted in part in the table since these are not sales for resale subject to Commission jurisdiction. However, copies of the sales contracts with large mainline customers (50 million cubic feet annually and over) are required to be filed with the Commission under Section 155 of the Regulations and a full report on all but very small customers, inclusive of sales volumes, revenues, average price and type of service is required in the pipeline companies' annual report of operations (FPC Form 2) to the Commission.

Section 5 of the Act enables the Commission to hold public hearing and investigate upon its own motion or upon complaints of local gas distributors, municipalities, state regulatory commissions or States directed against any rate, charge rule, practice or classification in a pipeline company's tariff. If after the investigation and hearing the Commission finds any of the above to be unjust, unreasonable, unduly discriminatory or preferential the Commission shall order the remedy needed.

Subsequent to Commission acceptance of a tariff filing, relatively few hearings over the years have been initiated pursuant to Section 5 by gas distributors or state authorities. However, the gas shortage curtailment plan filings have resulted in more such complaints.

The pipeline may not attach a new mainline industrial customer without first obtaining Commission authorization as provided under Section 7 of the Act. This limited control over mainline sales derives from Commission jurisdiction over all interstate transportation of gas.

Section 7 of the Act in general requires authorization (Certificate of Public Convenience and Necessity) for construction or extension of interstate pipeline facilities and the transportation or sale of natural gas by such facilities in interstate commerce inclusive of new pipelines and expansions of existing pipelines.

Under Section 7(e) of the Act, a pipeline applicant must demonstrate that its request "is or will be required by the present or future public convenience and necessity and that the applicant is willing to do the acts and to perform the services proposed..." -- otherwise the application will be denied.

A public hearing on all applications except for minor facilities is required with reasonable notice to all "interested persons," such as adjacent and possibly competing pipelines, gas distributors, municipalities along the pipeline route, land owners, state and federal agencies that may be interested, and others.

In the absence of an overriding vital objection in the public interest, such as in recent years environmental impact, the certificate application will be granted by the Commission if three principal tests are satisfactorily met: (1) adequate gas supplies, (2) adequate markets for the new gas sales and (3) the economic feasibility of the project.

The economic feasibility test has affected interruptible industrial sales and the resulting curtailments of service. Under this test, in addition to the overall cost of the project and the method and cost of financing the investment in facilities, the pipeline applicant is required to show sufficient revenues from the new or expanded sales -- sales for resale to local distributors and main line industrial sales -- to meet all costs and provide a reasonable return on the investment.

Revenue sufficiency in the case of an existing pipeline would generally mean that the new or additional sales would pay the incremental cost of the new facilities and would not require rate increases to existing customers who are not receiving a benefit from the expansion. In general, to achieve the necessary revenues, new or expanded industrial sales are required to offset winter space heating sales. In other words, the sales to the new customers and the increase in sales to existing customers should be made at reasonably high load factors so that the gas rates charged in the local markets will not be so high as to discourage market growth. As an example, because of a lack of a local manufacturing industry, the sales proposed in a Section 7 proceeding by a potential new distributor customer of a pipeline may be limited to only residential and commercial consumers and be principally space heating.

The very low load factor of the space heating sales (25 to 30 percent) may require such high rates for gas that only a few domestic and commercial customers would convert from oil or coal to gas fuel. The addition of large interruptible industrial sales would greatly improve the load factor, reduce the local rates and enhance the opportunity for market growth.

Other notable provisions of Section 7 of the Act are 7(a) and 7(b). Section 7(a) provides that the Commission, subject to certain restrictions, may order a pipeline under its jurisdiction, after notice and opportunity for hearing, to sell gas to a local distributor, municipally or privately owned, that the pipeline has voluntarily refused to service. Section 7(b) provides that a certificated sale of gas may not be abandoned by a pipeline or gas producer without first obtaining the Commission's permission. Other important parts of Section 7 provide for temporary certificates (these are also subject to Section 7(b) above) and the Commission's power to attach "reasonable terms and conditions" to the certificates issued.

During the 20 years, 1950 through 1969 -- a period of spectacular expansion for the natural gas utility industry -- the Commission issued over 4100 certificates for more than 150,000 miles of interstate pipelines. These authorizations for sales to new and expanded markets are indicative not only of the growth of the industry but also of certificate applicants' success in meeting the economic feasibility test, an important part of which is the addition of industrial sales for load factor improvement -- including both firm and interruptible sales.

Historically, the state regulatory commissions may not have approved but did not oppose interruptible industrial sales by intrastate gas distributors. In general, the higher load factors of these sales and the net revenues earned served to reduce rates charged for domestic service.

The lower rates for interruptible sales of gas for boiler fuel as compared with competitive fuels helped to reduce costs of local electric power generation and also helped to reduce air pollution which would have resulted if high-sulfur alternative fuels were burned.

B. The Development of Federal Power Commission Policy Concerning Gas Supply Curtailments

The pipeline capacity curtailments of interruptible industrial sales as needed continued as the only regular service reductions until 1970. Firm service had been unaffected over the years and gas supplies for market growth were ample. Until 1968, gas reserves increased despite the annual 6 percent increases in the gas production.

Interstate pipeline reserves and production which comprised over 60 percent of the Lower 48 States reflected the national pattern: reserves decreased from 198 Tcf (1967) to 134 Tcf (1973) and production increased from 11.8 Tcf (1967) to 14.2 Tcf (1972) but dropped to 13.7 Tcf in 1973.

The impact of the lessening supplies of natural gas was not really apparent until late 1970 when the first major pipeline curtailment case was brought to the Commission. Seven major pipelines curtailed service for the first time in the winter 1971-1972 because of gas supply shortages.

Design of End-Use Priority Curtailments

The Commission required the pipeline companies to file as a part of their effective tariffs any proposed curtailment of service plans they instituted as a result of short supplies. After analysis of the filings of 24 pipelines between 1969 and 1972, the Commission on January 8, 1973 in rule-making Docket No. R-469 issued a Statement of Policy Order No. 467 [1] which prescribed nine priorities of service based upon end-use of gas by the ultimate consumers that are to be followed by the interstate pipelines when they curtail gas service to their customers.

The nine service priorities are shown below:

END-USE OF GAS DURING CURTAILMENT - PRIORITY DESIGNATIONS

1. Residential, small commercial (less than 50 Mcf on a peak day).
2. Large commercial requirements (50 Mcf or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs, and pipeline customer storage injection requirements.
3. All industrial requirements not specified in (2), (4), (5), (6), (7), (8) or (9).
4. Firm industrial requirements for boiler fuel use at less than 3,000 Mcf per day, but more than 1,500 Mcf per day, where alternate fuel capabilities can meet such requirements.

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[1] As amended by Orders Nos. 467A and 467B.

5. Firm industrial requirements for large volume (3,000 Mcf or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements.

6. Interruptible industrial requirements of more than 300 Mcf per day, but less than 1,500 Mcf per day, where alternate fuel capabilities can meet such requirements.

7. Interruptible requirements of intermediate volumes (from 1,500 Mcf per day through 3,000 Mcf per day), where alternate fuel capabilities can meet such requirements.

8. Interruptible requirements of more than 3,000 Mcf per day, but less than 10,000 Mcf per day, where alternate fuel capabilities can meet such requirements.

9. Interruptible requirements of more than 10,000 Mcf per day, where alternate fuel capabilities can meet such requirements.

Curtailment would start with Priority 9 and proceed in reverse order to Priority 1, residential and small commercial service -- the last class of customers to be curtailed. The end-use priorities apply to all sales by a pipeline: sales for resale to local gas distributors and other pipelines and retail sales to main line industrial customers.

For example, each local gas distributor will provide the pipeline supplier with the daily volumes of gas needed in the winter and in the summer months to supply its consumers arrayed in accordance with the nine service priorities. The pipeline supplier will composite these for all of its local gas distributor customers and for all pipelines that it serves -- the pipeline buyers having made the same determinations and composites for their customers. Next, the pipeline supplier's own main line industrial sales will be added to the distributor and pipeline composite requirements. The overall total daily winter and summer sales of the pipeline supplier will thus be arranged by nine priorities and curtailment orders will be issued starting with Priority 9.

Order 467 provided the following instructions on the scope of the Commission's nine service priorities, exceptions to their observance and method of operation under the priorities during periods of service curtailments:

> "The priorities-of-deliveries set forth above will be applied to the deliveries of all jurisdictional pipeline companies during periods of curtailment on each company's system: except, however, that upon a finding of extraordinary circumstances after hearing initiated by a petition filed under Section 1.7(b) of the Commission's Rules of Practice and Procedure, exceptions to those priorities may be permitted.
>
> The above list of priorities requires the full curtailment of the lower priority category volumes to be accomplished before curtailment of any higher priority volumes is commenced. Additionally, the above list requires both the direct* and indirect customers* of the pipelines that use gas for similar purposes to be placed in the same category of priority."

* Mainline industrial and other retail customers of the pipeline are "direct" customers. The customers of the local gas distributors supplied by the pipeline are "indirect" customers.

Policy statements such as Order No. 467 are issued infrequently to give notice to the companies under the Commission's jurisdiction of the policies that will be followed in the future concerning specific important and generally controversial subjects that it will decide. Excerpts from Order No. 467 that explain the Commission's reasons for the end use service priorities follow:

> "The curtailment procedures to be followed must have as their basic objective the protection of deliveries for the residential and small volume consumers who cannot be safely curtailed on a daily basis and requiring, as the initial level of curtailment, reduction in deliveries for large volume interruptible sales."

The Commission then quoted as follows from its decision of January 5, 1973 in the Arkansas-Louisiana Gas Company curtailment proceeding (Opinion No. 643 Docket No. RP71-122) in regard to end-use of gas by the consumer and interruptibles and firm service priorities:

> "We are impelled to direct curtailment on the basis of end use rather than on the basis of contract simply because contracts do not necessarily serve the public interest requirement of efficient allocation of this wasting resource. In time of shortage, performance of a firm contract to deliver gas for an inferior use, at the expense of reduced deliveries for priority uses, is not compatable with consumer protection.
>
> Secondly, we have determined that interruptible sales are for the most part, predicated on end-use considerations; those customers, be they direct sales or indirect sales, who require gas

for human needs service or non-substitutable industrial service do not contract on an interruptible basis. Interruptible service, at the lower rates charged for such service envisions interruption. And accordingly, interruptible customers can most reasonably be expected to have alternate fuel facilities already operational. We conclude, therefore, that curtailment should first fall on those who have not historically borne the full-fixed costs of providing gas service, particularly since these customers are best prepared to accept interruptions in service and clearly do not require uninterrupted service for protection of life or property.

Finally, if curtailment reaches beyond the level of interruptible service into firm contract service, we commit ourselves to the proposition that large volume boiler fuel usage is inferior and should be curtailed before other firm service. Aside from the established physical fact that combustion of natural gas for raising steam in boilers and its subsequent conversion into electricity or mechanical energy results in a loss of roughly two-thirds of the heating value of the gas used -- which we regard as unacceptably inefficient in time of shortage -- we note also that those who use gas as boiler fuel generally can substitute other fuels more readily and at lower overall cost than other gas users; additionally, pollution control is more practical because of the large size of individual installations. Other fuels generally can be physically substituted in large boiler fuel application with less inconvenience and less possible adverse consequences than in other industrial applications, such as direct fired uses, and other uses demanding precise temperature control, flame characteristics, instantaneous response and atmosphere quality. Finally, subordinating boiler fuel use with its comparative ease of substitutability, to other large scale industrial and commercial uses should tend to minimize plant and business closings and the attendant economic loss from decreased production and payrolls, and the other personal hardships of unemployment [Footnote omitted].

In establishing the priorities-of-service for the use of the natural gas supply, it is obvious that some direct and indirect customers use their supply of natural gas for similar end-use purposes. Customers

> with similar usages for the fuel should be accorded the same treatment to avoid any undue discrimination or preference among them. Accordingly, we will place the direct and indirect customers in the same priority-of-service position as when their use of natural gas is comparable.
>
> In determining our priority-of-service listing, we are cognizant of the economic impacts that will flow from that listing. However, we believe that we have no choice but to impose certain restrictions on the sale of natural gas within the limits of our jurisdiction during this time of supply shortages. Our decision is made with full knowledge that certain sales to ultimate customers are beyond our jurisdiction. In those instances, we solicit the cooperation of State authorities to aid implementation of this program.

The Commission also issued two rule making dockets, Docket Nos. R-467 and R-468 to obtain comments on four proposals that may be adopted in the future and on certain changes proposed in its regulations to collect end-use data and implement the service priorities:

> Further, we are cognizant of the necessity for a continual review and implementation of policies as will forestall or hopefully preclude other pipeline companies from attaining similar shortage problems on their system and to promote the most efficient use of this natural resource during this time of short supply. To these ends, we solicit comments on several alternatives which may be considered in arriving at a rational solution to the optimum allocation of limited gas reserves at a time of shortage.

Only the first alternative or proposal is quoted because of its relevance to past Commission actions in regard to rate design and cost allocations:

> (1) Pipeline rates have been designed, in part, on the basis of economics. Thus, certain rates have been approved that encouraged indus-

> trial sales, which sales, in today's view, would be placed in a low priority status. Such rate design techniques will be reviewed to meet today's supply situation and should encompass such matters as elimination of conjunctive billing, modification of the Seaboard formula, separate rate for jurisdictional industrial service, elimination of annual contract demands and, in lieu thereof, the use of monthly or seasonal demands, and any other aspects of rate design relating to the principles of conservation of natural gas supply within the concepts set forth above.

The three other proposals dealt with minimum bills under gas producer contracts, end-use of gas imported from foreign countries and requiring the pipeline companies to supply a complete market study that would reflect end usage of their sales.

The nine service priorities established by the Commission leave to the pipelines the method of implementing the priorities during curtailment periods. In general, the following preliminary steps by the pipeline supplier are needed:

1. Collect the end-use data from their distributor and mainline industrial (direct) customers arranged by the nine priorities of service.
2. Establish the 12 monthly total gas volume entitlements and maximum daily volume requirements in each month, for each customer. In general, these volumes would be the actual deliveries to the customer in a 12-month period before the gas supply became deficient; i.e., 1969 or 1970, with some allowance for residential and small commercial load growth during subsequent years.
3. Array the gas volume data in (2) for each

customer in accordance with the nine service priorities.

4. For each of the 12 months, usually separated into winter and summer six-month periods, estimate the total supply of gas available to the pipeline company.

The company then would have available (a) the total monthly gas requirements and the maximum daily gas requirements during each month for each customer divided into the nine service priorities and (b) the total monthly gas supplies. The difference between the total gas supply and the total requirements for each month is the monthly supply deficiency or the volume of gas to be curtailed during a particular month.

The curtailment volume in any month will be prorated daily to each customer's requirements in reverse order of the nine service priorities -- starting with Priority 9, curtailing all deliveries in that priority before any deliveries are curtailed in Priority 8 and following the same procedure up through Priority 1 if necessary.

The composition by priorities of the customer's maximum daily needs in each month is important since a customer on his own account may normally curtail completely low priority boiler fuel sales during days of severe winter weather to protect domestic space heating requirements (Priority 1) and hence should not be ordered by the pipeline supplier to curtail gas on such days. On other relatively warm winter days the same customer may supply all nine priorities of service and should be curtailed as indicated above.

If the actual gas supply for a month is more or less than the estimate, the daily curtailment volumes will be adjusted accordingly. In general, no change in curtailment will be permitted for variances in customer requirements determined in the base period. 1/

The assignment of customer gas requirements to the nine priorities of service may cause disagreement among the customers or between the customers and the pipeline supplier. In this event, the matter may be brought to the Commission for hearing and decision.

It is important to note that a pipeline's curtailment plan is a method of allocating gas to its customers, but does not necessarily result in a specified level of consumption at the burner tip. Most of an interstate pipeline's sales are in turn sold by the pipeline's distributor customers. Under a curtailment program, the amount of gas which a distributor has to sell is directly influenced, but the sectoral distribution of the distributor's actual sales may differ from that which is implied by the curtailment method of the pipeline. For example, a distributor may have

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1/ There is some controversy concerning the issue of requirements based upon base period data. The question is whether or not to periodically update base period data to reflect market conditions.

sources of gas supply other than purchases from the interstate pipeline, such as direct purchases from producers, synthetic gas, or propane-air mixtures. The distributor may also be buying gas from two or more interstate pipelines with differing curtailment plans in effect. Moreover, the distributor's market structure may have changed somewhat from that which would be indicated in the historical base period data upon which the curtailment plan relies.

Order No. 467 was subjected to considerable criticism by pipelines, local gas distributors, industrial consumers, states and trade associations. Most agreed, however, that the end-use concept was proper.

The following are among the more critical comments: the firm and interruptible service classifications are not defined the same throughout the industry so that an identical end use could be classified either way, e.g., in Priority 5 or Priority 8; size classification should not be a factor -- only end use; end use of boiler fuel should be considered, e.g., boiler fuel for heating hospitals; sets nationwide priorities without considering varying conditions including availability of alternate fuels, patterns of reliance, prior investment by consumers in expectation of adequate gas supplies, prior investment by gas distributors in supplemental gas facilities.

The following table, which shows the percentage composition of the regulated gas utility industry market since 1950, is illustrative of the potential for severe economic impact through loss of industrial sales and revenues under the priority of service curtailments:

REGULATED GAS UTILITY ANNUAL SALES BY SERVICE CLASS,
PERCENT OF TOTAL SALES, 1950-1973

Year	Residential Priority 1	Commercial Priorities 1 & 2	Industrial Priorities 3-9	Other Priority 2
1950	33	10	54	3
1955	34	9	53	4
1960	34	10	51	5
1965	33	11	51	5
1970	31	13	53	3
1973	30	14	51	5

Source: American Gas Association, 1973 Gas Facts.

Severe reductions in industrial sales of local gas distributors and main line industrial sales of the pipeline will have a substantial impact upon local employment. Moreover, a reduction in industrial sales by the local gas distributors because of the service curtailments will require rates for residential and commercial sales to be increased to recover costs of service. Lower sales to the gas distributors will reduce the load factors of the pipeline suppliers and require rate increases to the local distributors.

Schedule II-1 shows for each reporting interstate pipeline the total volumes of firm gas service curtailed during the years 1970 through 1974, and the percentages that the curtailments are of annual firm requirements. In 1970, five companies curtailed firm service, increasing to twenty-two in 1974. Excluding intercompany curtailments, curtailments increased from 18 Bcf in 1970 to 1679 Bcf in 1974. Not shown on this schedule are a number of pipelines which have not as yet curtailed firm requirements.

Similar data are not available for interruptible service curtailments during the 1970-1974 period. However, for the twelve months ended August 1974, total interruptible service curtailments were 248 Bcf, or 38 percent, of "normal" interruptible service requirements; i.e., interruptible sales that would be made if gas supplies were available but excluding normal capacity curtailments.

C. Current Curtailment Plans of 38 Interstate Pipelines

As a result of the gas shortage, many pipelines are not able to fulfill their contracts to sell gas. Thus their curtailment plans pertain to a very pragmatic problem - the day-to-day and/or month-to-month allocation of insufficient supplies to their customers, occasionally numbering in the hundreds. The development of curtailment plans, the hearings, and ultimate acceptance by the FPC have been time consuming and controverted processes, and are expected to continue into the indefinite future.

Schedules II-3, II-4, and II-5 give specific case histories for three major interstate pipelines, directly or indirectly supplying gas ultimately used by electric utilities on the West Coast, East Coast and Louisiana and Mississippi. These case histories indicate the complexities of curtailment procedures.

Because of the different markets served by various pipelines as well as different supply situations, many of the curtailment plans in effect differ among themselves and from the guidelines promulgated by the FPC. Schedule II-2 shows the status as of March 1975 of the curtailment plans of 38 interstate pipelines for which data are available.

The 38 pipelines studied are representative of the interstate pipeline industry since 27 of the 34 companies classified as "major" pipelines are included.[1/] The 27 major pipelines accounted for 98 percent of the city-gate sales (i.e., sales to local gas distributors) and 77 percent of the mainline direct sales by interstate pipelines in 1974.

[1/] The remaining 7 of the 34 companies do not sell gas to local gas distributors or make direct industrial sales. The companies either sell only to other interstate pipelines or function solely as storage or transportation companies.

Schedule II-2, Column (1) identifies the pipelines and the geographical regions in which their sales are made. Column (2) indicates by the letter "X" the 27 pipelines classified as major. Column (3) shows the docket numbers assigned chronologically to the curtailment plans as they were filed in response to Commission order. Columns (4) through (6) designate the type of curtailment plan in effect on March 1, 1975 -- FPC end use, pro-rata by sales contract volume or other method. Columns (7) and (8) show the effective date and where applicable the expiration date of the filed curtailment plans.

Columns (9) through (13) show the principal reasons that plans other than the FPC end-use are under investigation. Column (14) for other than the FPC end-use plan shows whether interruptible service is the first to be curtailed -- except for small industrial sales, the FPC plan provides for curtailment of all interruptible service before firm service. Column (15) provides brief descriptions of the curtailment plans other than the FPC end-use plan.

Schedule II-2 shows that 16 pipelines are operating or are about to operate under the FPC end-use plan, 14 use the pro-rata contract plan, three use other plans, one applies the FPC plan to 50% of the company's seasonal gas supply and the pro-rata plan to the remaining 50% and five did not file with the Commission curtailment plans to be implemented in the event of supply shortages.[1]

Under the pro-rata contract plan end-use by the consumer is not considered, but interruptible service is usually the first to be curtailed. After all interruptible service is curtailed the pro-rata plan provides for equal percentage curtailment of each pipeline customer's firm daily entitlement. The curtailment percentage is the ratio of the daily volume to be curtailed to the sum of the daily entitlements of all customers. The pro-rata plan has been used historically by the pipelines to reduce deliveries when outages occurred because of storms, pipeline breaks and failure of pumping equipment in the compressor stations. The FPC end-use plan, by definition, would be unlikely to result in equal percentage curtailments because of variations in the end-use of gas by the consumers -- e.g., a local distributor serving only residential and commercial consumers -- the highest priority under the FPC plan -- may not be curtailed while at the same time another distributor with large industrial sales could be severely curtailed.

As column (9) of Schedule II-2 indicates, the Commission has under investigation the curtailment plans of 10 pipelines -- 9 of them major pipelines for deviations from its approved end-use plan: six of the investigations apply to the pro-rata plans discussed above.[1] However, nine companies with pro-rata plans are not under investigation; one of these, Great Lakes Transmission, receives its gas supply from Canadian sources. Two companies, Florida Gas Transmission and Michigan-Wisconsin had not reported any curtailments as of the end of 1974. Two companies, Cities Service Gas and Natural Gas Pipeline Company of America, according to Schedule II-1, had substantial firm gas curtailments in 1974 of 12.5% and 17.5%. The 1974 firm gas curtailments of the remaining four companies, according to Schedule II-1, ranged from zero percent for Colorado Interstate to 1.8 percent for Northern Natural Gas, 3.7% for Mid Louisiana Gas and 4.0% for Louisiana-Nevada Transit as compared with the average of 15.0% for all companies reporting curtailments. The endeavor by four pipeline companies to equalize the impact of curtailments among the customers by rate surcharges and credits (Column (11)) has met strong Commission opposition as discussed on Schedule II-4 in the case history of the Transcontinental Gas Pipeline Corporation. The Commission has found that these charges for undercurtailments and credits for overcurtailments as compared with the system average percentage of curtailment is contrary to the rate and certificate sections of the Natural Gas Act.

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[1] Algonquin Gas Transmission uses two curtailment plans as explained in Column (15).

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[1] Inclusive of the 50-50% FPC and pro-rata plan used by Transcontinental Gas Pipe Line.

In regard to Column (14) the FPC end-use plan requires that large interruptible sales made by the pipelines and their distributor customers be discontinued completely before any firm service is curtailed. Under the pro-rata plans and other plans, generally only the interruptible sales made by the pipelines are first discontinued.

Column (15) of Schedule II-2 indicates that in most cases the pro-rata and other curtailment plans appear to be tailored to the characteristics of the market served by the individual pipelines -- see Mississippi River Transmission for an example.

In summary, Schedule II-2 covers the curtailment procedures and status of plans of the domestic pipelines delivering practically all of the gas sold for resale to the local gas distributors and most of the gas sold directly to industries by the pipelines. The schedule shows in compact form the major problems and conflicts confronting the Commission and the regulated pipelines in their attempts to reduce historic gas requirements to a balance with the dwindling gas supplies and at the same time achieve maximum consumer protection.

D. Prospects of Gas Curtailment Electric Generation vs. Other Industrial Use

Under the Commission's end-use curtailment plan gas requirements for electric generation supplied under interruptible service contracts will be curtailed to the point of complete suspension before any substantial amounts of other industrial service are curtailed. This result follows from the wide difference in size of the power plant loads and those for other industrial use, as well as the differing contract types of the two categories of use. Thus, on a given pipeline system operating an end-use curtailment plan, electric utilities are likely to be cut off from gas prior to industrials.

The average U.S. power plant generating unit has a name plate rating of 142 megawatts which requires approximately 20,000 Mcf per day,[1/] double the 10,000 Mcf per day that institutes curtailment in Step 9 of the Commission plan. In contrast, the average gas industrial customer used about 76 Mcf per day in 1973.[2/] An interruptible industrial customer using the average of 76 Mcf or less per day and over the average of up to 300 Mcf per day would be in Step 3 of the Commission plan and would not be curtailed until all service to larger

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[1/] Derived from data in Steam-Electric Plant Construction Cost and Annual Production Expenses, Twenty-fifth Annual Supplement - 1972. Federal Power Commission, April 1974.

[2/] 1973 Gas Facts, American Gas Association.

use customers (Steps 4-9) had been suspended. Firm service industrial customers that do not use gas for boiler fuel purposes would be in Step 3 regardless of the volume of daily requirements or in Step 2 of the plan if the industrial use is for feedstock or process needs. Finally, it is unlikely that any substantial number of interruptible industrial customers other than power plants who are supplied by the interstate pipelines use in excess of the 1500 Mcf per day, the upper limit of Step 6 of the Commission plan.

Not only the level of gas consumption, but also the typical purchase contracts, tend to make electric utilities more susceptible to curtailments than industrial users. In the interstate market electric utilities buy gas on an interruptible basis more commonly than industrial users. During 1973, electric utilities in the interstate market purchased 71 percent of their gas under interruptible contracts, while industrial customers purchased 44 percent of their gas under interruptible contracts. Only in a very few states -- Florida and Nevada being examples -- does the proportion of firm gas reach a significant level.

The predominance of interruptible contracts by electric utilities reflects in many instances the use of gas as a secondary fuel, with coal or oil being the primary fuel. Chapter V provides greater detail on alternate fuel burning capability of gas fired electric utility plants.

CHAPTER III

CURTAILMENT OF NATURAL GAS SALES BY GAS DISTRIBUTORS AND INTRASTATE PIPELINES

As noted in the previous chapter, the amounts of direct sales to industrial and electric utility customers and sales for resale to distributors by interstate pipelines are directly affected by the interstate pipelines' curtailment plans. In turn, the sales by the distributors to their own customers reflect of course the total amount of gas available to them, determined by the supply situation and curtailment plan of the pipeline. However, an added ingredient to understanding gas availability for industrials and electric utilities served by distributors is the policy of gas distributors and/or state regulatory agencies, in light of FPC policies.

A substantial amount of gas, particularly for consumption by industrials and electric utilities, moves from the wellhead to the burner tip without passing through interstate jurisdiction. Under these circumstances, regulatory policies determined within the state and corporate policies are the essential factors in determining the disposition of intrastate gas supply by sector.

This chapter summarizes available information with respect to curtailment policies on a state level. In the initial section, a recent survey by the National Association of Regulatory Utility Commissioners is discussed and summarized.

The coverage therefrom is deemed sufficient for the conclusions drawn herein with respect to the states served largely by the interstate pipeline network. The second section deals with the results of research with respect to the intrastate market where there is substantial industrial and electric utility gas consumption wholly within intrastate commerce.

A. The NARUC Survey

In June 1974, the National Association of Regulatory Utility Commissioners (NARUC) through its Staff Subcommittee on Gas, sent two questionnaires to the regulatory agencies of the 50 states, the District of Columbia, and two territories to obtain current data principally on gas curtailments restrictions on new or added gas service, conservation and increasing the available supply of gas. On November 15, 1974, NARUC reported the results of its survey.[1/]

Of the 53 questionnaires sent, 32 responses were received in time to be included in the report. Seven of these did not have regulatory authority over the natural gas industry. The information provided by the remainder, 25 states,[2/] varied considerably in responses to all of the questions and in completeness of responses to each question.

1/ National Association of Regulatory Utility Commissioners: Survey of Action by State Regulatory Agencies and Intrastate Natural Gas Distributors to Meet Natural Gas Shortages, November 15, 1974.

2/ Includes only Oklahoma of the large gas producing states.

Gas Curtailments

Schedule III-1 summarizes the current methods of curtailing gas (curtailment plans) in each of the 11 states that supplied a description of the service priorities applicable during days of curtailment. The schedule shows in column (1) the classes of gas service supplied by distributors and in columns (2) through (12) the order of curtailment from first to last in each state; e.g., "1" means first service to be curtailed. Only two states, North and South Carolina reported plans practically the same as the Federal Power Commission's nine end use priorities although all of them except one gave residential service the highest priority or last to be curtailed. Five states that did not supply their curtailment plans in response to the questionnaires stated that they would implement the FPC end use plan.

In response to the inquiry as to 10 factors of potential use in establishing priority of service during curtailment, seven state commissions said "end use" and "practicality of alternate fuel use," six said "public interest", five said "economics," and three, "FPC guidelines." Generally, the curtailment plans provide lowest priority to the larger customers in any service class, as shown on Schedule III-1, based upon their greater economic ability to obtain alternate fuels.

Seventeen states replied to the question as to the priority system used by the gas pipelines supplying their states during curtailment: six states said FPC end use; six said "pro-rata" (i.e., by pipeline sales contract) and five said "mixed" (part pro-rata and part FPC end use).

Nine of the 19 states that responded to the question as to uniform curtailment if a local distributor received gas from more than one interstate pipeline supplier said the pipeline suppliers were not curtailing such local distributors uniformly; one state said the curtailment was uniform and the nine remaining states advised that gas was received by their local distributors from only one pipeline supplier.

The non-uniform pipeline curtailments (e.g., assuming two pipeline suppliers to a typical large distributor, one curtailing supplies by 20 percent and the other not curtailing on that day) present some problems at the distributor level particularly to large gas distributors serving many communities within a state. Under the example above it may be physically impossible because of lack of transmission facilities for the distributor to move gas between separate communities so as to equalize curtailments to industrial and other low priority consumers, the result being full service to interruptible industrial customers in some communities and curtailment of all industrial service in others.

Restrictions on New or Added Gas Services

Six states of the 25 responding to the question about restrictions and priorities on new or added gas service indicated that no statewide restrictions or priorities were in effect. Two states restrict additional residential gas service. Eight states prohibit all new gas sales but four of the eight have established priority lists for connections in the future. Nine states restrict expansion of commercial and industrial sales to existing customers.

Conservation of Gas

The state regulatory agencies responding to the questionnaires generally have not instituted programs to conserve gas but rather have encouraged the gas distributors to initiate their own programs. Only two states instituted measures for reducing requirements by a more efficient use of existing supply. Three states ordered a reduction in gas usage -- two for ornamental gas lighting and one ordered a 15 percent reduction in gas usage from the same period in the preceding year but postponed penalties for non-compliance.

Conservation measures adopted by the distributors and the regulatory commissions included the following:

public information by mass media on methods of conservation, prohibition of promotional advertising, restriction of swimming pool heating, and encouragement of insulation in residences. The primary effort according to most responses was directed toward public information on the need for and methods of conservation.

The claims of volumes of gas saved by conservation according to 18 responses, ranged from 2 to 15 percent of the total volume used -- however, the authors of the NARUC report recommended caution in interpreting the volume and percent of gas conserved because of the differing bases of calculation used. The volume saved (reported by 5 states) was 108 Bcf.

Reports by the American Gas Association indicate that conservation of gas by residential and commercial customers beginning in the Winter 1973-74 has a measurable effect on gas sales, although it is offset somewhat by additions of new customers.

Programs for Additional Gas Supplies

Twenty-five states responded to the question on regulatory commission action to encourage utility programs to obtain additional gas supplies. Thirteen of the responses indicated no such commission action; 12 indicated encouragement -- two allowed the distributors to pass on pipeline supplier exploration costs to consumers, four allowed the distributors to explore for gas and six encouraged utility peak shaving facilities for liquefied natural gas, storage of gas and synthetic gas.

Nine state commissions made rate allowances for distributor loans, investments or advances to obtain additional gas supplies. Sixteen commissions did not make such allowances.

Other Questions and Responses

Nine of 14 states responding indicated that distributors in their states had mutual assistance programs to exchange gas in the event of a critical temporary shortage. Seven states had mutual assistance programs in the form of joint LNG, SNG facilities and shared underground storage projects.

Fifteen of the 25 states responding said they had taken steps to have gas consumers use alternate fuels to meet natural gas shortages. Emphasis was directed particularly to interruptible gas uses. One state asked the interruptible customers to submit their alternate fuel requirements so that planning for supplies for the 1974-1975 Winter could be made by the state. Use of propane was encouraged; electric utilities were encouraged to use fuel oil, coal and propane.

Summary

Although the data obtained by the NARUC questionnaires is incomplete in coverage of the Lower 48 States, the 25 states responding account for over 50 percent of the national sales and only about 13[1/] percent of the marketed production. The report, thus, tends to fairly reflect conditions under the gas shortages in the populous, gas receiving states. In addition, the report is the most recent authoritative source of information on state activities in this regard.

The summary of the gas curtailment plans in Schedule III-1 shows that on a state basis most distributors have adopted the conventional type of curtailment -- first, interruptible gas, next firm industrial and last, residential and commercial service. The principles underlying curtailment methods, however, depart from the FPC criteria of reliance on end use only -- the practicality of obtaining alternate fuels is given equal weight with end use although the importance of end use is not downgraded. Also, the economic impact of gas curtailment, i.e., its effect on employment, is important at the state level. Three of the states particularly include hospitals, schools, nursing homes, and like institutions in their highest priorities.

The final impact of the pipeline supplier curtailments occurs within the various states where the gas reaches the burner tips. The need for alternate fuels by industries

[1/] Oklahoma, one of the 25 states, provides about 60 percent of the group's marketed production.

that have relied on natural gas where supplies were abundant is also in the local communities. Thus, the state regulatory commissions are naturally cautious about adopting any single plan of curtailment since they are responsible in their states for the economic impact.[1] The commissions, with good reason, would prefer to establish general guidelines and allow each local distributor to establish under the guidelines the curtailment plan best suited to its supply and markets both of which are best known to the distributor.

B. Curtailment Plans in Intrastate Markets

Texas

Texas utilities, with nearly 32,000 megawatts of generating capacity being gas-fired, burned 37 percent of the electric utility industries total gas supply in 1973. In light of the magnitude of the gas consumption by electric utilities in the State of Texas (1,277.8 Bcf in 1973), and the fact that over 98 percent of this gas is delivered from intrastate suppliers not subject to FPC regulation, it is important to obtain a clear understanding of the jurisdictional structure with respect to gas supply within this state.

Gas has been the primary boiler fuel in Texas since the 1920's and 1930's when a switch was made from coal;

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[1] 42 of the 48 states assign responsibility for curtailment of gas service to the regulatory commission.

today electric utilities in the state are approximately 90% dependent on this fuel. The enormous volume of gas burned within the state, virtually all of which is free from Federal control, is subject to the rules and regulations of the Texas Railroad Commission. This body dominates nearly every phase of the natural gas industry within the state, and the extent of their control is clearly defined in the following excerpt from the Gas Utilities Act:[1]

> Article 6050 to 6066, Inclusive, R.C.S.., 1925 (As Amended) --
>
> ARTICLE 6050. *Classification* -- The term "gas utility" and "public utility" or "utility", as used in this subdivision, means and includes persons, companies and private corporations, their lessees, trustees, and receivers, owning, managing operating, leasing or controlling within this State, any wells, pipe lines, plant property, equipment, facility, franchise, license, or permit for either one or more of the following kinds of business:
>
> 1. Producing or obtaining, transporting, conveying, distributing or delivering natural gas: (a) for public use or service for compensation; (b) for sale to municipalities or persons or companies, in those cases referred to in paragraph 3 hereof, engaged in distributing or selling natural gas to the public; (c) for sale or delivery of natural gas to any person or firm or corporation operating under franchise or a contract with any municipality of other legal subdivision of this State; or (d) for sale or delivery of natural gas to the public for domestic or other use.
>
> 2. Owning or operating or managing a pipe line for the transportation or carriage of natural gas,

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[1] Eighty-second Annual Report of the Railroad Commission of Texas; Gas Utilities Division, 1973.

> whether for public hire or not, if any part of the right of way for said line has been acquired, or may hereafter be acquired by the exercise of the right of eminent domain; or, if said line or any part thereof is laid upon, over, or under, any public road or highway of this State, or street or alley of any municipality, or the right of way of any railroad or other public utility; including also any natural gas utility authorized by law to exercise the right of eminent domain.
>
> 3. Producing or purchasing natural gas and transporting or causing the same to be transported by pipe lines to or near the limits of any municipality in which said gas is received and distributed or sold to the public by another public utility or by said municipality, in all cases where such business is in fact the only or practically exclusive agency of supply of natural gas to such utility or municipality, is hereby declared to be virtual monopoly and a business and calling affected with a public interest, and the said business and property employed therein within this State shall be subject to the provisions of this law and to the jurisdiction and regulation of the Commission as a gas utility.
>
> Every such gas utility is hereby declared to be affected with a public interest and subject to the jurisdiction, control, and regulation of the Commission as provided herein. (Acts 3rd C.S., 1920, P. 18.)

A primary function of the Railroad Commission is the allocation of inadequate gas supplies. This function stems from its authority to "regulate and apportion the supply of gas between towns, cities, and corporation.[1] The Railroad Commission believes that this authority gives it the right to apportion the state's entire intrastate gas supply, although this contention is currently being disputed in a

[1] The discussion of legal authority and regulations in Texas is largely adopted from two reports by the Governors Energy Advisory Council of the State of Texas: Project No. L/R4, "Legal and Regulatory Policy Aspects of Energy Allocation," and Project No. L/R1, "Existing Energy Law and Regulatory Practice in Texas." These reports were submitted by the Office of the Attorney General in November of 1974.

number of cases including: City of Austin, City of San Antonio, Lower Colorado River Authority, v. Railroad Commission, Civil No. 213478 (53rd Dist. Ct., Jan. 1974). Under the above mentioned authority, the Commission issued an order in January 1973 which set up general rules governing the priorities to be followed by gas utilities in the event of a gas shortage. The gas utilities were then required to submit their specific curtailment programs to the Railroad Commission. The priority system of the Railroad Commission, which would be utilized until those of the individual utilities had been approved, is as follows:

A. Residences, hospitals, schools, churches and other human needs customers.

B. Small industrials and regular commercial (less than 3,000 Mcf per day) and use for pilot lights and accessory equipment.

C. Large users of gas for fuel or as a raw material where no alternative exists.

D. Large users of gas for boiler fuel or other fuel users where alternate fuels could be used.

E. Interruptible sales.

The majority of the gas utilities in the state elected to adopt the priority list established by the Railroad Commission, although separate curtailment programs were submitted by Lone Star Gas Co., Pennzoil Pipeline Co., Union Texas Petroleum, and Lo Vaca Gathering Co. in 1973. In the list formulated by the Railroad

Commission, as well as in most others submitted, the electric utilities with firm contracts have a low priority status and are curtailed immediately following interruptible customers.[1/] [2/] Gas supplies were curtailed to a number of Texas electric utilities in 1973 and 1974, including Houston Lighting and Power, Texas Power and Light, and Dallas Power and Light. More severe curtailments were suffered by the customers of Coastal States Gas Corp. and its subsidiary Lo Vaca Gathering Co. The utilities served by these gas suppliers provide electric service for a substantial portion of South-Central Texas, including the cities of Austin and San Antonio. Power plants operated by the Lower Colorado River Authority, the City Public Service Board of San Antonio, and the Utility Fund of Austin burned considerable amounts of oil in 1973 and 1974 due to recurring interruptions in gas supplies. Gas curtailments were less severe in 1974 than in 1973, partially because of a relatively mild winter, but these curtailments have become a matter of major concern for the state's electric utilities as well as the Railroad Commission.

A second item of concern for the electric utilities in the state is the Railroad Commission hearing which began in June, 1975. This hearing is being held to "allow all

[1/] The majority of gas burned by electric utilities and industrials in Texas is purchased under firm contracts.

[2/] In a few specific cases, the Railroad Commission has granted short-term relief from curtailments to power plants.

gas utilities, owners or operators of gas-fired boilers, and any interested party to appear and present evidence regarding the reduction or elimination of natural gas as a boiler fuel in Texas and the development of a reasonable schedule for phasing out the usage of natural gas as a boiler fuel in Texas."[1] The Railroad Commission feels that "the public interest requires, among other things, a determination of the reasonableness of reducing or eliminating natural gas as a boiler fuel."

A major contention of the opponents of such a move is that the Railroad Commission cannot overrule existing contracts. However, in the case of a public utility the rule which may prevail provides that "a corporation organized for a public purpose may not contract away its ability to perform its obligations."[2] A further consideration is that "parties cannot circumvent or limit the power of the Commission in administering the conservation laws by private agreement."[3] These two rules, coupled with the general

[1] "Amended Order Setting a Statewide Hearing," in re: "Elimination of Natural Gas Used as a Boiler Fuel in Texas," Railroad Commission of Texas, Gas Utilities Division, Docket No. 600, April 11, 1975.

[2] *Lone Star Gas Co. v. Municipal Gas Co.*, 117 Tex. 331, 3 S.W. 2d 790, 792 (1928); *Gulf C. + S.F. Ry. Co. v. Morris*, 67 Tex. 692, 4 S.W. 156, 158 (1887).

[3] *Railroad Commission v. Mack-Hank Petroleum Co.*, 186 S.W. 2d 351, 357 (Tex. Civ. App.--Austin 1945), *rev'd on other grounds*, 144 Tex. 393, 190 S.W. 2d 802 (1946).

acknowledgement of the Texas courts of the broad powers of the Railroad Commission, seem to indicate that a total phaseout is indeed a strong possibility. The power of the Railroad Commission was acknowledged by the Court of Civil Appeals in Danciger Oil and Refining Co. v. Railroad Commission:

> "We recognize the rule that, in the regulation and control of private rights and properties of individuals by administrative agencies of the state, the interests of the individual, so far as consonant with the public welfare, should be jealously guarded and protected; and no authority not clearly delegated to such agency by the Legislature, or necessarily implied from that express delegation, should be sustained. . . . Because of the nature of the subject matter involved here, however, that line of cases does not furnish an accurate analogy. In the instant case, the commission, as the designated agency of the Legislature, was given the mandatory direction to carry out the mandate of the Constitution to prevent waste of the natural resources. That duty was expressly enjoined upon it. In construing the validity of its acts in undertaking to do so, we must consider the nature, character, and extent of the subject matter placed under its jurisdiction and the purposes sought by the Legislature to be accomplished. So considered, any order of the commission bearing a reasonable relationship to the general duty imposed upon the commission, which is not unreasonable nor unjust, and which is reasonably calculated to prevent waste, comes, if not within the express powers granted to the commission, clearly within those necessarily implied; and is "confined to the obvious purposes and directions of the statute."

Spokesmen for the Railroad Commission have stated that they do not wish to immediately abolish boiler fuel gas, as this would have a detrimental effect on both the pipelines and the utilities. One estimate is that the conversion process might be of a ten-year duration, although an industry spokesman felt the process would take 30 years if done properly. Three possible options available to the Railroad Commission in order to achieve the phaseout are: (1) phase in a tax incentive to convert to other fuels over a ten-year period; (2) seek a new federal law permitting low-priced gas bought under old contracts to be resold at higher prices (as to a gas utility serving customers in another state) to compensate for the cost of conversion or (3) develop phaseout schedules on a case-by-case basis.[1] Decisions on the elimination of natural gas as a boiler fuel in Texas will be made in the near future, and they will be the object of close scrutiny by the state's electric utility industry.

Louisiana

The volume of gas consumption in the electric utility sector of Louisiana (369 Bcf in 1973) ranks third in the U.S., with only Texas and California surpassing this level. Gas is supplied by both intrastate and interstate sources, with intrastate suppliers accounting for the lion's share of the market, approximately 72 percent. Electric utilities in the interstate portion of the market have been hit hard

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1/ Electrical Week, May 19, 1975.

by curtailments, especially those supplied by United Gas Pipeline, the major interstate source of gas in the state.

In late 1973, the Extraordinary Session of the Louisiana Legislature enacted Act No. 16 establishing a Division of Natural Resources and Energy. This new Division was the result of a study on energy matters within the state submitted to the Governor by an Energy Advisory Council. A system of priority use for intrastate gas was established by the Division of Natural Resources, but this system has not been put into effect, and to do so would require an emergency order from the Governor. Such an order is not anticipated at this time. The priority schedule which would go into effect in the event of a serious intrastate gas shortage places large volume boiler fuel use (industrial and electric utilities) in priorities eight and nine of a nine-step plan. Large volume boiler fuel users with alternate fuel capabilities (priority nine) would be the first group to be curtailed,[1/] followed by large volume boiler fuel users with no alternate fuel capabilities (priority eight). The Commissioner of Conservation has the authority to curtail the gas supply of those plants which he feels could be modified to accomodate alternate fuels with "minimal cost and delay." Gas required for the protection of public health, safety and welfare,

[1/] Interruptible gas sales represented less than 7 percent of total Louisiana gas sales in 1973, and are not set out in the priority schedule separately.

including maintenance of gas and electrical service to homes, schools, hospitals and services would fall in priority one. An interesting feature of the Louisiana curtailment structure is that no purchaser of gas shall be subject to a curtailment in excess of 10 percent of daily contracted demand. That is, after all users in class nine are curtailed by 10 percent, cut-offs would begin in class eight. The result of this type of plan is that all users are forced to sacrifice to some degree, rather than completely eliminating the supplies to one specific group of users. What would follow the curtailment of 10 percent of class one's gas, should a continuation of the curtailment be necessary, has not been specified.

No actions similar to the proposed phaseout of boiler fuel gas in Texas have been initiated in Louisiana, and the feeling in this state regarding this matter seems to be "wait and see" at this time.

Oklahoma

Electric utilities in Oklahoma consumed 271 Bcf in 1973, nearly 8 percent of the national total. This gas was supplied almost entirely by intrastate sources, and therefore falls under the jurisdiction of the Oklahoma Corporation Commission rather than the FPC. The Corporation Commission is a regulatory body which is now provided with policy recommendations on energy matters by the State Department of Energy, a new agency created in 1974 with the enactment of HB1638. The allocation of fuels is an issue of primary importance to this agency.

No curtailment orders have been issued in Oklahoma, nor has a priority structure yet been established. The shortage of natural gas does not appear to pose a serious threat in Oklahoma at this time, and the utilities in this state have full confidence in their gas supplies. However, even though existing gas-fired power plants are expected to maintain or exceed their current levels of gas consumption, new plants built in this state will be fueled mainly by coal or nuclear sources. This switch will become more evident in the later years of the 1970's.

C. The Impact on Electric Utilities and Industrials of Curtailments by Distributors and Intrastate Pipelines

The supplies of gas available to local distributors in the states outside of the major Southwest producing states depend upon deliveries by the interstate pipelines principally of Southwest gas and to some extent of gas imported from Canada. The curtailment of deliveries by most of the gas distributors in the country may therefore be expected to reflect the priorities in the curtailment plans of their pipeline suppliers -- curtailment first of all interruptible deliveries including boiler fuel and next of any firm service large boiler fuel sales. Residential and small commercial and industrial sales, hospitals and schools will be the last to be curtailed.

Thus, with some differences, the curtailments ordered by the pipelines will be reflected in curtailments by the distributors. The pipeline curtailments, those on the Commission end-use plan and others temporarily in effect, are aimed at interruptible sales and boiler fuel sales as a class. But the distributor curtailment directly affects individual industrial customers.

At the state level, consideration must be given to the difficulties of the individual customers in obtaining alternative fuels in much greater quantities than before the gas shortages. Also the substantially higher prices to be paid for the substitute fuels may affect the competitive position of an industry in the market place. Since these difficulties threaten plant shut-downs with consequent loss of employment in many communities, the state regulatory commissions may be expected to order suspension of deliveries to power plants or frequent curtailments before reducing other industrial deliveries. Such action would be in accord with the FPC findings quoted below:[1/]

> "Finally, subordinating boiler fuel use with its comparative ease of substitutability, to other large scale industrial and commercial uses should tend to minimize plant and business closings and the attendant economic loss from decreased production and payrolls and the other personal hardships of unemployment."

[1/] Federal Power Commission Opinion No. 643, Docket No. RP 71-122, Arkansas-Louisiana Gas Co., 1/5/73.

The deteriorating gas supply situation in Texas indicates a similar but longer range treatment of power plant sales in that state. The general statement on priority of service by the Texas Railroad Commission in the last two steps (D and E) has the same curtailment effect as the Commission's end use priorities. Deliveries of gas obtained from intrastate suppliers in other Southwest producing states may be expected to follow the curtailment procedures being introduced in Texas if the supply situation in these states worsens.

CHAPTER IV

THE PROJECTED AVAILABILITY OF NATURAL GAS TO ELECTRIC UTILITY STEAM-ELECTRIC PLANTS 1975 TO 1980

With the increasing shortage of natural gas, the outlook for gas availability is bleak. It is the purpose of this chapter to set out specific forecasts of gas availability to gas-burning electric utility power plants, on a plant-by-plant basis.

The flow of gas to electric utilities was analyzed in Chapter I. As indicated in that chapter, the majority of gas consumed by electric utilities is purchased from gas pipelines and distributors. Less than 5 percent of gas consumed by electric utility power plants is purchased directly from producers. Thus, the amount of gas available to electric utilities will depend on the supply of gas to pipelines and distributors and the curtailment policies of these pipelines and distributors.

As also indicated in Chapter I, approximately 62 percent of the gas consumed by electric utilities in the United States moves in intrastate commerce. This gas is not subject to FPC jurisdiction and thus its consumption is not affected by the curtailment plans of interstate pipelines. However, a substantial volume of gas -- 1,294 Bcf in 1973 -- moves to electric utilities through interstate pipelines. In the states of Texas, Louisiana, Oklahoma and New Mexico, the majority of gas burned by electric utilities moves thereto wholly in intrastate commerce. Most of the gas consumed in Florida by electric utilities in Florida is transported by an interstate pipeline but is purchased from producers in Texas and Louisiana by the electric utilities. Gas to most other electric utilities is purchased directly or indirectly from interstate pipelines.

Chapters II and III indicated that there is considerable divergence in the curtailment policies of different gas companies, reflecting markets, supply and regulatory constraints. However, electric utilities are generally among the first to be cut off from gas supplies if demand exceeds supply. The end-use plans of interstate pipelines would theoretically eliminate large volume interruptible electric utility and industrial use before any other category is curtailed. Many of the pro-rata plans of interstate pipelines also result in initial curtailments falling upon electric utilities. To the extent that state regulatory agencies have promulgated policies with respect to natural gas curtailments for gas companies falling within their jurisdiction, the practical results of these policies will be to reduce the availability of natural gas to electric utilities.

Schedule IV-1 shows the projected availability of natural gas to electric utility power plants annually from 1973 to 1980, by plant, company, state and region. On Sheet 29, the total for the U.S. is shown to decline dramatically, from 3.4 quadrillion Btu's in 1973 to 1.7 quadrillion Btu's in 1980. This amounts to a 49 percent reduction in seven years. As shown on the following summary table, predominantly interstate markets are projected to decline more acutely than intrastate markets.

CURRENT AND PROJECTED GAS CONSUMPTION
FOR ELECTRIC UTILITY STEAM GENERATING PLANTS
(Quadrillion Btu's)

	Predominantly Interstate Markets	Predominantly Intrastate Markets a/	Total U.S.
1973	1.43	2.01	3.44
1974	1.20	2.10	3.30
1975	0.79	1.93	2.72
1976	0.31	1.81	2.12
1977	0.24	1.76	2.00
1978	0.22	1.70	1.92
1979	0.18	1.65	1.83
1980	0.15	1.59	1.74

a/ Texas, Oklahoma, Louisiana and New Mexico.

For the total U.S., electric utility gas consumption declined somewhat in 1974 compared with 1973. However, predominantly intrastate markets showed a slight increase, while predominantly interstate markets experienced a decrease in electric utility gas consumption. The increase in intrastate markets reflects not only the greater relative deliverability of gas, but also the warmer weather prevailing in 1974 which ameliorated curtailments. Although electric utility gas consumption in the interstate market declined in 1974, it is herein estimated that the decline would have been more severe were it not for warm weather and the impact of conservation and the recession.

Factors such as weather, conservation and the recession affect the demand for gas in the residential-commercial and industrial sectors, and thus the supply of gas for electric utilities. Since by regulatory fiat or operating practice electric utilities are given "low priority" status under most curtailment plans, a decrease in demand by higher priority sectors results in increased availability for electric utilities.

Electric utility gas consumption in predominantly interstate markets is projected to decline by one-third to 0.8 quadrillion Btu's in 1975. This projection would be substantially lower were it not for key assumptions with respect to continuation of the recession and conservation in 1975. After 1975, a resumption of economic growth is assumed, and the overall gas supply situation is projected to continue to deteriorate, resulting in virtual elimination of interstate sales for power plant consumption. Another key assumption is that all but one interstate pipeline will be curtailing on some end-use basis after 1975. This would result in electric utilities initially bearing the brunt of the shortage. During this period, as the "cushion" of electric utility gas consumption diminishes, industrial curtailments will grow increasingly severe.

By 1980, it is projected that within predominantly interstate markets electric utilities in only two states will have appreciable gas consumption. It is projected that some electric utilities in Kansas, with indigenous gas some of which moves intrastate, could still be burning gas. In Florida, a substantial amount of gas transported to electric utilities is not subject to pipeline supply curtailment. With respect to the amount of gas subject to pipeline supply curtailment in Florida, the small proportion of high priority markets in this state and the type of curtailment plan also facilitates continued sales to power plants by the interstate pipeline. Nevertheless, electric utility gas consumption in both states is forecast to decline substantially.

California, New York and Arkansas, three states in which electric utilities have traditionally burned large amounts of gas, are shown to have little gas available for electric utility gas consumption after 1975. Thus, for predominantly interstate markets, it may be concluded that gas will not be a major boiler fuel in the future. Even if substantially more gas were available for all sectors than the volumes assumed herein, the electric utility sector would not be the recipients. The industrial sector, generally of higher priority than the electric utility sector, would be available to absorb any additional volumes.

As shown in the summary table, gas consumption by electric utilities in predominantly intrastate markets would not decline as rapidly as in interstate markets. However, this forecast assumes business as usual, especially in Texas. It should be noted that the Texas Railroad Commission is considering the phaseout of gas as a boiler fuel in Texas, which might also lead to similar actions in other gas producing states. Thus the projections to 1980 could be viewed as an upper limit. If this projection were to prevail in Texas, industrial gas consumption might well be reduced.

It should be noted that both the interstate and intrastate forecasts assume an end of the recession by 1976 and a resumption of real economic growth thereafter. Moreover, the forecasts do not reflect any significant reduction in industrial demand for gas due to energy conservation. Dampening of industrial demand for gas could increase the availability of gas for other sectors, including the electric utility sector. As a practical matter, however, the above assumptions with respect to economic conditions and conservation have a more significant effect on the earlier years of the forecast - 1975 and 1976 - than the later years to 1980.

The following two sections explain and discuss in more detail the forecasts. In Section A predominantly interstate markets are discussed, and in Section B predominantly intrastate markets (Texas, Louisiana, Oklahoma and New Mexico) are discussed.

A. Projections for Predominantly Interstate Markets

The supply of natural gas available in the future to a power plant attached to the interstate pipeline network is determined largely by the supply situation on the specific interstate pipeline from which it draws its supplies. Although the overall interstate pipeline supply situation is bleak, there are sufficient differences among the individual pipelines and distributors which have significant effects on the amount of gas for specific power plants.

On a given interstate pipeline, future supply availability for power plants is dependent upon several factors. Deliverability on the pipeline system for all classes of users in forthcoming years is, of course, the foremost consideration. For any particular class of users, the share which they may expect to obtain of the future overall supply is determined largely by the curtailment plan in effect on the pipeline specifying the manner in which supply inadequacies will be handled. The dissimilarities of curtailment plans in use by different interstate pipelines have already been discussed. For power plants, the critical question is the extent to which they are treated as the first class of users to be curtailed, and the degree to which others also suffer early curtailments, on each individual pipeline system.

An additional factor of great importance is the aggregate composition of different user classes on particular pipelines. Some systems have predominantly residential and commercial loads, others have greater industrial and power plant demands in relationship to their residential and commercial volumes. Even with given industrial and power plant shares of the total pipeline demand, different pipelines differ with respect to the proportion of firm and interruptible deliveries. These relationships among several user classes, termed the pipeline end-use profile, significantly affect the way in which curtailment plans will impact upon future gas supplies available to power plants.

In order to illustrate these effects, assume that two pipelines each projected a 10 percent decline in system deliverability, each had a curtailment plan in which all interruptible industrial and power plant customers were curtailed first with firm industrial and power plant customers curtailed only after all interruptible loads had been eliminated and with residential and commercial users curtailed only after all industrial and power plant volumes has been cut off. If one of the two pipelines had 50 percent residential and commercial customers, 40 percent firm industrial and power plant users and 10 percent interruptible loads, then the 10 percent supply decline on the system as a whole would totally eliminate all the interruptible volumes. If the other pipeline had only 20 percent residential and commercial, 40 percent firm and 40 percent interruptible consumption, then the 10 percent decline in systemwide deliverability would result in only a 25 percent curtailment of interruptible customer volumes. Given the practical fact that residential and commercial users will not be curtailed while any interruptible users are obtaining even a small volume of gas, the immediate conclusion is that the larger the residential and commercial proportion of the pipeline end-use profile, the more vulnerable the interruptible customers are to drastic curtailments.

The same naturally holds for firm industrial and power plant users with respect to the magnitude of residential and commercial end-use on their pipeline supplier's system. Firm users, however, are also affected by the proportion of interruptible usage. Taking the same two hypothetical pipelines as before, a further 10 percent decline in supplies available to the first supplier would all be taken out of firm volumes, and would amount to 25 percent of the firm usage, since the first 10 percent supply loss had already eliminated the interruptible categories on that pipeline. On the second pipeline, however, the next 10 percent supply loss would not affect firm users at all, because there was still interruptible gas being delivered and available for curtailment. Thus, the "low priority" usage acts as a cushion for the higher priority usage.

The relationship between a power plant and its source of interstate natural gas also affects the supply expectations. A power plant obtaining its gas by direct sale from a pipeline may have a different supply picture than one obtaining gas indirectly from the same pipeline by resale from a local distribution company which has purchased gas from the pipeline. In the former case, the theoretical impact of the curtailment plan would be no different from the actual impact. In the latter case, if the curtailment instituted by the distributor differed from that of the pipeline, the theoretical results of the pipeline plan might not be carried out.

The general framework for projecting the availability of gas to power plants in predominantly interstate markets involved three steps for each pipeline serving, directly or indirectly, electric utilities. As the initial step, overall pipeline supply was projected. The second step was obtaining or estimating the end-use profile -- sales by sector -- for the relevant pipelines. The third step was to allocate the supply to specific power plants by reference to the curtailment plans of the relevant pipelines and/or distributors.

As the basis for supply projections, the Form 15 reports filed by the interstate pipelines in early 1974 were utilized. These projections were in some cases modified by reference to the latest FPC data on near-term curtailments and more recent projections published in annual reports to stockholders and prospectuses. The Form 15 forecasts take into account projected deliveries from presently dedicated reserves but do not take into account deliveries from reserves which may be obtained in the future. For the near-term, the addition of new supplies would not alter significantly the total sales of a pipeline, but in the longer term the assumption of no additional supplies becomes more precarious. As will be discussed, however, a reasonable estimate of additional future supplies would not significantly alter the availability of gas to electric utilities through 1980.

End-use profiles were obtained for many pipelines from filings in curtailment cases at the FPC. For those pipelines for which no end-use information was available from curtailment cases, end-use profiles were estimated from available data.

By reference to the supply projection and the end-use profile, the impact of the curtailment plan in effect as of the beginning of 1975 (see Chapter II) was estimated. While many pipelines are operating under curtailment plans which follow the nine priority end-use structure, there are a number of pipelines whose current plans differ to varying degree from that structure. It was assumed in preparing the forecasts that the plan in effect at the beginning of 1975 would be operative through the end of the year. It was assumed that after 1975 most curtailment plans would be end-use oriented. Thus, strictly pro-rata plans were assumed to be abandoned in favor of end-use plans. The forecasts in some cases could be higher after 1975 if these changes in curtailment plans were not assumed.

The forecasts also incorporate certain assumptions with respect to the impact of conservation practices largely in residential and commercial sectors and the recession on industrial demand. Unadjusted for these considerations, the 1974 estimated consumption would show 10.4 percent less power plant consumption in predominantly interstate markets than actually occurred in that year. Hence, for the year 1975, a 6 percent downward adjustment in industrial requirements was made to reflect the recession, and a 4 percent downward adjustment in residential usage was made to reflect conservation. Economic growth was assumed to resume thereafter, although the effect of conservation was assumed generally to remain.

At this point it should be noted that the forecasting methodology reflects static assumptions with respect to the supply and requirements of interstate pipelines. The Form 15 supply projections, as modified for more recent data, do not take into consideration production from new reserves which may be acquired. With respect to demand, the base period data utilized in implementing curtailment plans does not take into consideration increases in demand in the high priority sectors.

Schedule IV-2 shows the historical trend in reserves additions, production (net withdrawals from reserves) and total reserves for interstate pipelines. As shown on the schedule, interstate production has declined from a peak of 14.2 Tcf in 1971 and 1972 to 13.7 Tcf in 1973 and 12.9 Tcf in 1974. End-of-year reserves have declined 39 percent since 1967, reflecting insufficient reserves additions to replace production. In the last three years net additions to reserves have been zero.

The extent to which the Form 15 supply projections may be tenuous depends on the future level of reserves additions by interstate pipelines. If interstate pipelines continue to be unable to acquire new reserves, then the Form 15 supply projections will be the fact.

Including the more prolific years of reserves additions, reserves additions by interstate pipelines have averaged 6.4 Tcf per year since 1963. An illustrative supply projection to 1980 is shown below, assuming interstate reserves additions of 3 Tcf in 1975 and 6.4 Tcf each year thereafter.

ILLUSTRATIVE INTERSTATE SUPPLY PROJECTION

(Billions of Cubic Feet)

	Production from Reserves as of December 31, 19	Production from Assumed New Reserves	Total Production
1974	12,888	--	12,888
1975	12,148	--	12,148
1977	10,409	910	11,319
1980	7,794	2,386	10,180

What the above analysis suggests is that interstate supply will decline to 1980, but the amount of decline is dependent upon the assumed level of reserves additions.

These illustrative supply projections may be compared to overall interstate patterns to estimate their impact on various categories of end-use. Gas available to electric utilities has already been forecasted at 662 Bcf in 1975, 113 Bcf in 1977, and 74 Bcf in 1980.[1] If residential and commercial uses are allowed to grow at 2 percent annually from their 1973 level of 6,089 Bcf,[2] then it would reach 6,996 Bcf by 1980. The effect of these estimates is shown below, with industrial consumption treated as a residual, taking whatever is not assigned to the residential, commercial, electric utility and other categories.

ILLUSTRATIVE INTERSTATE SUPPLIES BY END-USE
(Billions of Cubic Feet)

	1975	1977	1980
Residential & Commercial	6,335	6,591	6,996
Industrial	4,365	3,882	2,450
Electric Utility	662	113	74
Other	787	733	660
TOTAL	12,149	11,319	10,180

1/ Excluding Texas, Louisiana, Oklahoma, New Mexico and Florida because of the predominance of intrastate supplies and/or transportation of supplies.

2/ FRC data for 1973. Texas, Louisiana, Oklahoma and New Mexico excluded.

The impact upon industrial consumption, even assuming the drastic curtailments in electric utility supplies discussed in other sections of the study, is to reduce it to 47 percent of its 1973 level by 1980, a shortfall of 2,710 Bcf from the 5,160 Bcf received by industrial customers in 1973.[1] Thus, in order to alleviate the industrial curtailments, additional supplies will have to amount to 2,897 Bcf in 1980, allowing for the resultant increase in other use, in order to provide 2,710 Bcf of additional natural gas for industries. Since the supply projection used herein already includes additional new production of 2,386 Bcf in 1980, the increase would have to be more than twice that great in order to offset expected industrial curtailments. Even then, with new production in 1980 amounting to 5,283 Bcf in 1980, or 68 percent of production that year from currently existing reserves of interstate pipelines, no increase is likely in electric utility supplies from the level forecast to 1980 in the study. Thus the benefit of any additional gas supplies will not accrue to electric utilities.

Assuming that electric utilities bear the brunt of curtailments to the extent that their 1980 supply is expected to be only 5.8 percent of its level in 1973, there is still a drastic impact on industrial supplies. Even with the optimistic assumption that new interstate reserves additions amounted to 6.4 Tcf per year from 1976 onwards,

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1/ FRC data for 1973. Texas, Louisiana, Oklahoma and New Mexico excluded.

resulting in production from new reserves amounting to 2,386 Bcf in 1980, as compared to production from current reserves of 7,794 Bcf in that year, the supplies for industrial users would be barely 47 percent of their 1973 level. If production from new reserves is less than projected, industrial curtailments will rise further. Even if new reserves were in excess of those illustrated, industrial users could easily absorb the resulting production.

The consumption of natural gas by industries varies considerably from region to region in absolute amount, in proportion of national industrial usage, in comparison with consumption for other uses in the same region, in distribution between firm and interruptible sales, in share of the industrial market served by interstate supplies, and in rapidity with which industrial curtailments are expected to become significant.

Along the Atlantic Coast, comprising the regions of New England, Appalachia and Southeast, industrial supplies will probably be substantially reduced well before 1980 unless substantial new reserves are obtained by pipelines serving the regions. The situation of Tenneco and Transcontinental Gas Pipe Line Corp. are typical in these regions, and their extremely severe supply losses in the near future will all fall on industrial users, since the magnitude of electric utility gas consumption, excluding that transported to Florida, plants, is relatively small. Industrial users in the Southeast obtaining supplies from Southern Natural Gas Co., however, have a future supply outlook somewhat better than the rest of the Atlantic Coast.

The Great Lakes region faces largely the same situation as that prevailing along the Atlantic Coast. Based upon production projections from presently dedicated natural gas reserves, the interstate pipelines which serve significant shares of the market, except for Michigan Wisconsin Pipe Line Co., anticipate substantially reduced industrial loads well before 1980. Even on Michigan Wisconsin, industrial service will probably be substantially cut.

Despite having had a cushion of electric utility gas, amounting to nearly 20 percent of the regional consumption in 1973, the Northern Plains region is expected to experience very rapidly declining industrial supplies. Its dominant pipeline suppliers, Northern Natural (which delivered over half of the region's gas in 1973) and Natural Gas Pipeline Company of America, both project rapidly falling deliverability from current reserves. Only the dedication of substantial new reserves to pipelines serving the region would, to some degree, reduce prospective industrial curtailments.

Far less pessimistic is the future of industrial supplies to the interstate portions of the Mid-Continent region. One factor which partially cushions the impact of curtailments on industrial users is the existence of 37 percent regional consumption by electric utilities in 1973. Another factor is the relatively less severe supply forecast for Cities Service Gas Co., which may satisfy a significant portion of its industrial needs, even in 1980, from currently dedicated reserves.

Industrial consumption in the Gulf Coast is mostly supplied from intrastate sources, and is discussed separately.

The Rocky Mountain region, served largely by Colorado Interstate Gas Co., faces less severe losses of industrial supplies, based upon existing reserves. Curtailment of industrial demand is expected to increase steadily, although it is possible that firm industrial customers may not be curtailed to any significant degree until nearly 1980.

The situation in the Pacific Southwest, dominated by California, and by El Paso Natural Gas Co., indicates significant possible industrial curtailments in 1975. By the late 1970's, based upon production estimates from currently dedicated reserves, much industrial consumption may be eliminated except for those customers obtaining some portion of Pacific Gas & Electric's imported Canadian supply.

Because the Pacific Northwest region has substantial supplies of gas imported from Canada, which are not projected to decline during the period studied, its industrial supply outlook is better than for California. However, with electric utility consumption almost nil, and with residential and commercial usage smaller than in most parts of the Nation, any supply losses on that part of the region's natural gas originating in the Southwest part of the United States will be reflected proportionately in industrial curtailments.

In short, the industrial outlook is worst along the Atlantic Coast and Great Lakes, slightly better, if at all, in California and the Pacific Southwest, and better in varying degrees in other parts of the U.S.

The following section describes step by step the forecast of gas availability for power plants in California. Electric utilities in California consume more gas than electric utilities in any other state in the predominantly interstate market and the forecast for California is considered representative of the interstate market.

Forecast of Gas Supplies Available to California Steam-Electric Power Plants, 1975-1980

The forecast of annual supplies of natural gas available to the 35 California steam-electric power plants considered in this study is based upon the increasing domestic shortage, interstate and intrastate, of natural gas supplies available to the state since 1970. The shortages require curtailments of gas deliveries instituted under curtailment plans prescribed by the Federal Power Commission (Commission) for two[1/] of the three interstate pipelines delivering gas at

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[1/] El Paso Natural Gas Company and Transwestern Pipeline Company. The third pipeline, Pacific Gas Transmission Corporation, transports Canadian gas to California for the account of Pacific Gas and Electric Company. Sufficient quantities of gas are expected to be available to PGT to avoid curtailments of deliveries.

the state border, and by the California Public Utilities Commission (PUC) for gas utilities under its regulatory jurisdiction.

The purpose of the Federal and state curtailment plans is to protect gas service to residential, small commercial and industrial, and other consumers where alternative fuels, oil and coal, are infeasible to obtain or to use. Under both the Commission and PUC orders, the steam power plants are the first to have gas deliveries curtailed; i.e., have the lowest priority of service on days when gas is in short supply and therefore must use alternative fuels for electric generation.

Twenty-two of the 35 California power plants are supplied with gas directly or indirectly by Southern California Gas Company (SCG).1/ Twelve (its own plants) are supplied with gas by Pacific Gas and Electric Company (PG&E). The remaining plant2/ is supplied by a California gas producer, Atlantic Richfield Company.

The calendar year 1973 is the base year used for the forecast of gas supplies for the California power plants. The forecast method employs for SCG and PG&E: (1) the curtailment plans of El Paso and Transwestern; (2) El Paso's estimate of the distribution of natural gas requirements in

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1/ San Diego Gas and Electric Company buys it entire gas supply from SCG including that burned in power plants.

2/ Mandalay Plant of Southern California Edison Company.

its market area by the priority steps of its curtailment plan (referred to as the "end-use profile"); (3) the proportions of total gas supplies received from the interstate pipelines and from California production; (4) the projections of future supplies, 1974-1980 from interstate pipeline sources and local production; (5) the estimated additional gas supplies available for use in power plants because of the 1974-1975 recession and the conservation of gas; (6) a summation of the foregoing in the form of the percentages of 1973 power plant deliveries available for the 1974-1980 requirements; (7) a test of (6) against reported actual power plant gas supplies in 1974; and (8) application of the percentages in (6) to each of the 34 California power plants served by SCG and PG&E to forecast gas supplies for the years 1975 through 1980.[1]

Transwestern curtails gas deliveries under the Commission's prescribed plan with nine priority of service steps. El Paso curtails under a five-step priority of service plan prescribed after hearings by the Commission. Despite the differences in number of priority steps, the plans are essentially the same and both provide that deliveries to power plants will be the first curtailed during periods of gas shortages on the pipelines. The PUC plan for SCG and PG&E

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[1] The volumes of actual deliveries for 1973 and 1974 are available from the EPA tabulation and monthly reports to the Commission on FPC Form 423.

also provides that steam electric plants will be curtailed first.

El Paso has supplied data on the end-use of system gas deliveries by the five priority-of-service steps of its curtailment plan. The steps of the plan and the percentage of system gas deliveries applicable to each step are shown in the table below.

EL PASO NATURAL GAS COMPANY
CURTAILMENT PLAN AND END-USE
GAS REQUIREMENTS OF SYSTEM CUSTOMERS

Steps:	Priority of Service	End-Use Profile (percent)
1.	Residential, small commercial needs (less than 50 Mcf on a peak day)	38.4
2.	Large commercial, industrial feed-stock, process and plant protection needs. Storage needs.	16.6
3.	All industrial needs not covered in (2), (4) and (5).	20.5
4.	Boiler fuel use, 1500-3000 Mcf per day. 1/	0.9
5.	Boiler fuel use over 3000 Mcf per day. 1/	23.6
		100.0

1/ Where alternative fuel capabilities (exclusive of propane and other gaseous fuels) can meet the requirements.

Source: El Paso Natural Gas Co. tariff and filings with the Federal Power Commission.

As the table shows, large boiler fuel use such as for steam electric plants comprises about 23.6 percent of the total gas requirements supplied by El Paso -- some 75 percent of which are in California. El Paso supplied about 50 percent of California's total 1973 gas receipts through sales to SCG for resale in Southern California and to PG&E for resale in Northern California. The large proportion of El Paso's deliveries of the total California gas supply and the wide geographical distribution to final consumers of this gas support applications of the El Paso end-use profile percentages in the table to allocate 1973 base year California supplies among the five priority of service steps as a starting point in the forecast of future gas supplies for the California power plants.

The tables below show the 1973 gas supplies of SCG and PG&E by supply sources and the allocation of total gas supplies of each company by the El Paso priority of service steps (end-use profile).

SOUTHERN CALIFORNIA GAS COMPANY AND PACIFIC GAS AND ELECTRIC COMPANY 1973 GAS SUPPLIES AND SOURCES OF SUPPLY

	SCG		PG&E	
	Bcf	Percent	Bcf	Percent
1973 Gas Supply	966	100.0	1020	100.0
Suppliers				
El Paso	610	63.1	378	37.1
Transwestern	274	28.4	--	--
Pacific Gas Trans.	--	--	363a/	35.6a/
California Producers	82a/	8.5a/	279a/	27.3a/

a/ Estimated.

Source: 1973 Annual Reports, Form 2, to the Federal Power Commission; 1973 California Gas Report to the California Public Utilities Commission.

SOUTHERN CALIFORNIA GAS COMPANY AND PACIFIC GAS AND ELECTRIC COMPANY ALLOCATION OF 1973 GAS SUPPLIES BY PRIORITY OF SERVICE STEPS OF THE EL PASO NATURAL GAS COMPANY CURTAILMENT PLAN

	SCG	PG&E
	(Bcf)	(Bcf)
1973 Gas Supply	966[a]	1020[a]
Priority of Service Steps		
1	371	392
2	161	170
3	198	209
4	9	9
5	227	240

a/ Estimated.

The next step in the forecast is to project the gas supplies available to SCG and PG&E for the years 1974 through 1980 from each supply source shown previously. All sources except Pacific Gas Transmission are estimated to experience declining supplies. PGT supply is expected to remain the same as 1973 since the basis is Canadian gas reserves. The El Paso and Transwestern projections are taken from their Annual Reports of Gas Supply, Form 15, to the Commission. The California gas production estimates and supplies from PGT are taken from the 1973 California Gas Report.

The table on the following page summarizes the projected future gas supplies of SCG and PG&E from all sources determined as described above for the calendar years 1974 through 1980. Columns (3) and (5) show the anticipated reductions from 1973 in total gas supplies.

SOUTHERN CALIFORNIA GAS COMPANY AND PACIFIC GAS AND ELECTRIC COMPANY PROJECTED TOTAL GAS SUPPLIES 1974-1980 AND SUPPLY REDUCTIONS FROM 1973 SUPPLIES

(Billions of Cubic Feet)

	SCG		PG&E	
Year (1)	Total Gas Supplies (2)	Reduction from 1973 (3)	Total Gas Supplies (4)	Reduction from 1973 (5)
1973	966	--	1020	--
1974	892	74	869	151
1975	779	187	800	220
1976	695	271	746	274
1977	643	323	723	297
1978	594	372	687	333
1979	546	420	656	364
1980	503	463	625	395

The projected reductions from 1973 in total gas supplies represent anticipated further curtailments of gas services over those required in 1973. These would be applied ordinarily to reduce the 1973 power plant deliveries in Step 5 under Federal and state curtailment plans as shown in the table on the following page.

SOUTHERN CALIFORNIA GAS COMPANY AND PACIFIC GAS AND ELECTRIC COMPANY ESTIMATED TOTAL GAS SUPPLIES FOR POWER PLANTS

(Billions of Cubic Feet)

	SCG	PG&E
1973 Gas Supply	227	240
1974 Reduction	(74)	(151)
1974 Supply-Volume	153	89
Percent of 1973	67.4%	37.08%

However, it is estimated that for the years 1974 and 1975 and some part of 1973, additional volumes of gas should be available to the power plants as a result of conservation of gas use by the residential customers and the effect of the nationwide recession on industrial gas requirements. The effect of these reductions in demand by these other sectors translates to somewhat over 14 percent when applied to 1974 power plant gas supplies and would increase the percentage of 1973 supplies shown in the above table from 67.4 to 82.04 for SCG and from 37.08 to 51.73 for PG&E. The same percentage increases are assumed for 1975 but not for the years 1976 through 1980.[1/]

The following table sums up the curtailment effect of the estimated reduced gas supplies, 1974-1980, heretofore described on all market sectors supplied by SCG and PG&E with particular emphasis on future power plant gas supplies.

[1/] The effect of conservation would be offset by growth in 1976 under current California policy.

Section A of the table shows the anticipated gas curtailments on the SCG system in accordance with the El Paso and California curtailment plans[1] adjusted in 1974 and 1975 for additional gas supplies transferred to power plants from residential and industrial requirements as a result of conservation practices and the recession. The anticipated reductions in system gas supplies for 1973 occurring in the years 1974 through 1980 are deducted first from Step 5 -- power plant deliveries -- until these are fully suspended (beginning 1976) and thereafter deducted from Steps 4, 3, and 2 (in 1980) as needed.

Section B of this table shows the similar results of future curtailments on the PG&E systems calculated as described for Section A of the table.

Section C isolates the estimated power plant supplies only and adds the percentages of 1973 gas deliveries expected to be available to the power plants; 82.04 percent of 1973 in 1974 and 32.26 percent in 1975 for SCG, and 51.73 percent and 22.98 percent, respectively, for PG&E. The forecast percentages of 1973 power plant supplies show the steep declines expected, particularly by 1975, and the zero level of deliveries in 1976 and thereafter.

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[1] As previously noted, the Transwestern curtailment plan is in practical effect the same as that of El Paso.

ESTIMATED GAS SUPPLIES AVAILABLE TO SOUTHERN CALIFORNIA GAS AND PACIFIC GAS & ELECTRIC COMPANY
1973 - 1980

(Billions of Cubic Feet)

A. SCG

Priority of Service Steps	1973	1974	1975	1976	1977	1978	1979	1980
1	371	371	371	371	371	371	371	371
2	161	161	161	161	161	161	161	132
3	198	198	198	163	111	62	14	--
4	9	9	9	--	--	--	--	--
5	227	186	73	--	--	--	--	--
TOTAL	966	925	812	695	643	594	546	503

B. PG&E

Priority of Service Steps	1973	1974	1975	1976	1977	1978	1979	1980
1	392	392	392	392	392	392	392	392
2	170	170	170	170	170	170	170	170
3	209	209	209	184	161	125	94	63
4	9	9	9	--	--	--	--	--
5	240	124	55	--	--	--	--	--
TOTAL	1020	904	835	746	723	687	656	625

C. Power Plant Supplies

SCG

Priority of Service Steps	1973	1974	1975	1976	1977	1978	1979	1980
5 Bcf[1]	227	186	73	--	--	--	--	--
% of 1973	100.0	82.04	32.26	--	--	--	--	--

PG&E

Priority of Service Steps	1973	1974	1975	1976	1977	1978	1979	1980
5 Bcf[1]	240	124	55	--	--	--	--	--
% of 1973	100.0	51.73	22.98	--	--	--	--	--

[1] From Step 5 of Sections A and B of this table.

Since the forecast percentages shown in Section C of the table will be applied to actual 1973 gas deliveries of each of the 34 power plants supplied by SCG and PG&E to forecast future supplies, the 1974 derived percentages were compared as shown below with actual 1974 percentages for SCG and PG&E to the extent that data are available.

GAS SUPPLIES TO POWER PLANTS
1974 AS A PERCENT OF 1973

	SCG	PG&E
Section C	82.04	51.73
Actual 1974	79.60	--
12 months ending 6/30/74	--	66.30
12 months ending 9/30/74	--	53.90

Source: Table 6, 1973 California Gas Report; Pacific Lighting Corporation Annual Report Supplement 1974 for SCG; PG&E Prospectuses, October 9 and December 17, 1974.

In addition, in the 1973 California Gas Report, SCG forecasts 94 percent curtailment of total steam-electric plant requirements in 1975, 98 percent in 1976 and 97 percent in 1980. PG&E forecasts in the Report that no deliveries of gas will be made to its own power plants (98 percent of total power plant gas requirements) during the years 1975 through 1982.

The foregoing tests of the estimated percentages of 1973 power plant gas supplies indicate that the percentages are sufficiently accurate within the limits of present information and anticipated future trends of gas supplies available to SCG and PG&E to forecast the gas supplies for the 34 California power plants.

A sample of the forecast of gas supplies to one of the 22 power plants supplied by SCG is shown below. The same format and method were used for the remainder of the plants supplied by SCG and PG&E.

CITY OF BURBANK PUBLIC SERVICES - BURBANK PLANT

Gas Supplier: Southern California Gas Company

Source of Supply:	Calif. Prod.	El Paso N.G. Co.	Transwestern Pipeline Co.	Total
1973 Actual	5.9%	65.0%	29.1%	100.0%

	Millions of Cubic Feet			Millions of C. F.	Billions of Btu 3/
1973 (Actual)	106	1169	523	1798	1875
1974 (Estimated) 1/	87	959	429	1475	1538
1974 (Actual)	99	1089	487	1675	1747
1975 (Estimated) 2/	34	377	169	580	605
1976-80 (Estimated)	0	0	0	0	0

1/ 1973 supply x 82.04%.
2/ 1973 supply x 32.26%.
3/ At average 1043 Btu per cubic foot.

The percentages used in the forecast for the Burbank Plant are those for the total gas supplies for all of the power plants supplied by the SCG. Total percentages are used also for the individual plants supplied by PG&E. Since these are system average forecast percentages, deviations will occur among the individual plants as shown above for Burbank in 1974. However, as total gas supply for the power plants declines sharply the deviations in 1975 and subsequent years should be minimal.

This view is supported by the predictions of SCG and PG&E in the 1973 California Gas Report as stated above.

The Mandalay plant of Southern California Edison Company obtains over 99 percent of its gas supplies from California production by purchases from Atlantic Richfield Company, a gas producer. The forecast of future gas supplies from California production available to this plant is that made by Southern California Edison in the 1973 California Gas Report. The estimated supplies vary from 66.7 percent of 1973 in 1975, to 18.6 percent in 1980.

B. Projections for Predominantly Intrastate Markets

In the composite, gas consumption by electric utilities in the states of Texas, Louisiana, Oklahoma and New Mexico is projected to decline by 21 percent between 1973 and 1980. This projected decline reflects only to a limited extent the impact of curtailments by interstate pipelines, since electric utilities in these states acquire most of their gas through intrastate sources. More importantly, the projected decline reflects deteriorating supply conditions in intrastate markets.

Due to ceilings on prices for gas which interstate pipelines could pay, intrastate pipelines for many years have been successful in obtaining a large proportion of new gas found in the onshore producing areas. Most of new gas reserves attached by interstate pipelines have come from the Federal Domain offshore Louisiana. However, although intrastate pipelines have attached a large share of new onshore reserves, the overall level of onshore reserves additions has been inadequate.

It is estimated that in 1973, total intrastate production (consumption) of gas was 8.8 Tcf. From 1969 to 1973, total onshore reserves additions in the U.S. averaged only 5.7 Tcf per year. Thus, the total amount of new gas theoretically available for intrastate consumption has been insufficient to support current levels of consumption.

Texas is a case in point. In 1973, electric utilities in Texas burned more than one-third of the total volume of gas consumed by electric utilities in the United States, and over half of the gas burned by electric utilities in what is denoted herein as the predominantly intrastate market. Total Texas intrastate production in 1973 was approximately 4.9 Tcf, which accounted for most of total gas consumption by all sectors in this state. Total reserves additions in Texas have averaged less than a third of these consumption volumes. Thus, total gas supply for consumption in Texas may gradually diminish in coming years.1/

As a result of these adverse supply trends, some curtailments in Texas have already occurred. The Texas Railroad Commission has placed electric utility boiler fuel in

1/ In 1974, both interstate and intrastate production declined in Texas.

a low priority in the event of curtailments by pipelines. Moreover, reflecting the deteriorating supply-demand outlook, and the potential impairment of gas service to industrial customers, the Texas Railroad Commission is considering the phaseout of electric utility gas consumption.

The forecasts developed herein may be considered as "business as usual" and do not take into account potential future regulatory reactions. For each of the electric utilities burning gas, the supply situations of their respective suppliers were reviewed. Reflecting the differing supply situations of various suppliers of gas to power plants, some diversity of trends is projected for the power plants on Schedule IV-1. Sources of data included annual reports to stockholders and prospectuses of both buyers and sellers of gas, as well as reports by the Texas Railroad Commission.

Although gas consumption by electric utilities is projected to decline, this "business as usual" approach also suggests increasing curtailments of industrial plants. There will be trade-offs between industrial and electric utility gas consumption in Texas, but the quantification of that trade-off is precarious unless assumptions are made as to future regulatory actions.

The projections for Oklahoma show modest increases in gas consumption through 1980. This forecast contrasts with those for all other states, but reflects the unique situation in Oklahoma. Two companies in that state accounted for 90 percent of electric utility gas consumption, and both have been relatively successful in acquiring new gas supplies. Both have significant control over the disposition of their gas either through ownership of the pipelines or the actual gas reserves. In their 1974 annual reports to stockholders, both companies provided estimates of gas supplies for electric generation which have been incorporated into the projections on Schedule IV-1. A review of the overall gas supply-demand situation in Oklahoma also suggests sufficient gas availability for electric generation and industrial needs.

Electric utility gas consumption in New Mexico is projected to decrease from 1974 to 1976, reflecting curtailments by an interstate pipeline serving part of the state. From 1976 to 1980, electric utility gas consumption is shown to be stable, reflecting the apparent circumstances of the major intrastate seller of gas in that state. The gas burning utilities in New Mexico do not foresee major curtailments of gas service by intrastate suppliers. These favorable circumstances result from the increasing exploratory effort in southeast New Mexico based upon increased intrastate prices.

In Louisiana, electric utility gas consumption is projected to decrease by 35 percent between 1973 and 1980. A substantial portion of this decline in the first two years of the forecast is attributable to worsening curtailments by interstate pipelines. These curtailments will also reduce gas consumption by industrial concerns buying interstate gas. However, the intrastate pipeline system in Louisiana has been quite successful in obtaining new gas supplies, and some electric utilities and industrial consumers have been able to acquire gas supplies directly from producers. According to available annual reports by electric utilities, plants tied to intrastate supplies are in no imminent jeopardy.

CHAPTER V

THE CURRENT AND PROJECTED USE OF ALTERNATIVE FUELS BY GAS-BURNING UTILITY POWER PLANTS

As indicated in the previous chapter, the amount of gas available to electric utilities throughout the United States will diminish substantially. The impact of the gas shortage on electric utilities will be to shift a substantial portion of their energy needs to other fuels. It is thus the purpose of this chapter to analyze the ability of gas-burning power plants to use alternate fuels, and to appraise the potential alternate fuel demand by electric utilities in light of reductions in gas supply.

A. Current Alternate Fuel Burning Capacity of Gas-Burning Electric Utility Power Plants

Each of the 415 gas-burning electric utility steam generating plants previously designated has been analyzed with special emphasis on its primary fuel requirements and ability to burn alternate fuels. As an initial but integral step in this analysis, a summary of key data from Form 423's and the FPC Form 36's is set out on Schedule V-1. The Form 36, "Emergency Fuel Convertability Questionnaire," presents data which was filed in February 1973 and is in some cases outdated, but represents the only available data on a relatively consistent basis of alternate fuel burning capacity and is a useful starting point.

Column (1) of Schedule V-1 lists for each region and state the gas-burning power plants included in the 415 plant study; Column (2) shows the amount of gas burned by each plant in 1973; and Column (3) shows the 1973 megawatt rating of the plant. Based upon a print-out of Form 423 data for calendar year 1974 obtained by Foster Associates, Inc., from Applied Data Research, Inc., Columns (4) through (7) indicate the relative purchases of oil, gas and coal for each plant. Column (8) identifies the fuel or fuels which the plant was originally designed to burn, taken from Steam-Electric Plant Factors, published by the National Coal Association. Column (9) gives a verbal description of the alternate fuel capabilities of the plants. This verbal assessment largely reflects the FPC Form 36. In some cases where the 1974 fuel consumption indicated substantial change in fuel burning capability since the end of 1972 (the effective date of the Form 36 data), and other factors partially confirmed that this had occurred, the Form 36 data were modified accordingly.

Thus, for example, the first gas-burning power plant listed is Kendall Square, owned by Cambridge Electric Light Company in Massachusetts. The plant burned 500 million cubic feet in 1973 and has a 67 megawatt rating.

In 1974, 41 percent of its fuel consumption came from gas and 59 percent from oil, and the Form 36 indicates that oil is the primary fuel. It may then be surmised that a reduction in gas deliveries could be accommodated by greater utilization of oil without plant modification. As in many other cases, the original fuel burning design (Column (8)) had been modified over the years.

Schedule V-2 is a state-by-state summary of the data from Schedule V-1 with the plants grouped by state and FRC region. The number of plants, megawatt rating, and 1973 gas consumption are given for four categories of plants, defined as follows:

(1) Gas is the primary fuel but an alternate fuel could be burned with no boiler-generator derating.

(2) Gas is the primary fuel and an alternate could be burned, but some derating would result or the alternate could not be burned in all boilers.

(3) Gas is the primary fuel and no alternate exists.

(4) Gas is a secondary fuel and is indicated as being burned as an alternate fuel or in conjunction with other fuels.

While the states are listed by FRC region in both Schedule V-1 and Schedule V-2, in the following analysis they have been grouped according to similar consumption patterns.

B. Summary of the Alternate Fuel Capability in the Interstate Market

New England proper, New York, Pennsylvania, New Jersey, Delaware, the District of Columbia and Maryland constitute an area in which gas was generally consumed as an alternate fuel for oil. Gas was burned in 27 plants in these eleven states in 1973, and was considered to be an alternate for oil in 24 of these. Two plants burned gas as an alternate for coal, and one plant burned gas and oil on a co-equal basis. The total 1973 electric utility gas consumption in these states was 73.0 Bcf (46.8 Bcf in New York), or 2.2 percent of the U.S. power plant total.

A second group of states which exhibited similar consumption patterns was that of: Virginia, West Virginia, Kentucky, Tennessee, North Carolina, South Carolina, Georgia and Alabama. In these eight states gas was again mainly a secondary fuel, but the principal fuel in this region was coal rather than oil. The 18 plants in this area which burned gas in 1973 consumed a total of 62.5 Bcf, less than 2 percent of the U.S. total. Of these 18 plants, 13 were fueled primarily by coal, 1 by oil, and 2 burned gas along with another fuel. The 16 plants in which gas played a secondary role accounted for 93 percent of the region's gas consumption. The two remaining plants, one in Alabama and one in Georgia, considered gas to be their primary fuel. However, both plants possess full alternate fuel capabilities, and would suffer no boiler derating if an alternate fuel were consumed.

The seven state area of Ohio, Illinois, Indiana, Michigan, Iowa, Wisconsin and Minnesota combined for a total 1973 gas consumption of 189.4 Bcf, just under 6 percent of the U.S. total. Some 36 percent of the gas total was burned in 24 plants which considered this fuel to be their primary source of energy. Of these 24 plants, 17 had full alternate sources of power (usually coal), 5 would suffer some minor derating if an alternate were burned, and 2 had no alternate fuel capability. The 7 plants with either limited or no alternate capability consumed 19.2 Bcf in 1973, slightly more than 10 percent of the region's total consumption. Gas was usually burned as an alternate for coal in this region. In 43 of the 80 gas-burning plants gas was considered to be an alternate fuel. Coal was listed as the primary fuel in 41 of these 43 plants, which accounted for 47 percent of the area's 1973 gas consumption. Gas was burned in conjunction with either oil or coal in an additional 13 plants, which consumed 17 percent of the region's gas in 1973.

A six state area accounted for 11.8 percent of the electric utility gas consumption in 1973, with 70 plants burning 401.3 Bcf. The six states were: Colorado, Kansas, Nebraska, Missouri, Arkansas and Mississippi. The utilities of this region placed heavy reliance on gas, but in most cases alternative sources of energy were available under certain limiting restrictions. The majority of the plants in this area (52 of 70) considered gas to be their primary fuel. In all but one of these 52 plants, an alternate fuel could have been burned in place of gas. While only one plant had no alternate capability, 27 of the 52 plants would either suffer some degree of boiler derating when burning an alternate fuel, or they could not consume an alternate in all boiler units. The impact on each plant when burning an alternate is described in Column (9) of Schedule V-1. Of the 52 plants which burned gas as their primary fuel, 33 listed oil as their alternate, 10 listed coal, 8 listed both oil and coal, and one had no alternate.

The State of Mississippi was included in this region, and at first glance might seem out of place, since four of the state's seven plants indicated that they had no alternate fuel capability. However, the oil consumption in each of these four plants has increased substantially in every year since 1972 as a result of gas curtailments. The 1974 data shows the percent of total Btu consumption derived from oil to range from 21 percent to 82 percent for the four plants, with three of the four over the 66 percent mark.[1/] These plants were therefore placed in the category

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1/ Mississippi Power & Light Co., the major gas-burning utility in the state, has spent over $50 million to modify its plants to burn oil as well as gas. Mississippi Power Company, the second major gas-burning utility in the state, was curtailed 69 percent of contracted supply in 1973 and 80 percent in 1974. As a result, the company is now generating approximately 65 percent of its power with coal, as well as increasing amounts of fuel oil.

of having gas as a primary fuel with oil as a partial alternate.

Virtually all gas consumed by electric utilities in Arkansas is received from interstate suppliers on an interruptible basis. The Arkansas Power & Light Co. accounted for 90 percent of electric utility gas consumption in 1973, but has increased its dependence on fuel oil over the past two years due to gas curtailments. It has made plans for both a nuclear and a coal-fired plant, using Wyoming coal.

North Dakota, South Dakota, Montana, Wyoming and Utah constitute an area in which gas played a minor role in the electric utility sector. None of the eight plants in this region which consumed gas considered it to be their primary fuel. It was listed as an alternate for coal in five of the plants, and an alternate for oil in the other three. (However, one plant in South Dakota which listed oil as the primary fuel did consume about three times as much gas as it did oil in both 1973 and 1974.) These five states burned 7.2 Bcf in 1973 on an alternate fuel basis, 0.2 percent of the U.S. total.

The dominant characteristics in Arizona, Nevada, California and Florida, were: (1) substantial gas consumption; and (2) high degree of substitutability between oil and gas. These four states consumed nearly 20 percent of the electric utility sectors' gas in 1973, and virtually all of the 673.3 Bcf burned could have been replaced by oil. In fact, the 1974 consumption data suggests that a switch from gas to oil was being made in a number of plants in this area.

California epitomizes this group of states. The 35 plants in California burned 441.6 Bcf, over 13 percent of the U.S. total. Of these 35 plants, 34 listed gas as the primary fuel with oil as an alternate. In 1974, over 40 percent of the total Btu consumption in 22 of the 35 plants was derived from oil. A similar situation was observed in both Arizona and Nevada, where 14 of the 16 gas-burning plants listed gas as the primary fuel and oil as the alternate. In Arizona, 8 of the 11 gas plants received over 48 percent of their total 1974 Btu's from oil. The Nevada plants were of similar design, and substantial amounts of oil were consumed in 1974, but the pattern of oil-for-gas substitution was not as striking in this state.

Florida was included with these West Coast states because it fits the two established criteria. Gas consumption in Florida totaled 145.8 Bcf in 1973, and nearly all electricity generation could have been fueled by oil with no boiler derating. Florida was similar to the other states in that the overwhelming majority of plants (25 of 27) burned some combination of oil and gas, with both fuels being significant sources of energy. Although only 5 of the Florida plants listed gas as the primary fuel, 18 of the total 27 operated on a fuel supply which was at least one-third gas.

The next three-state area is that of: Idaho, Oregon, and Washington. In these states gas played little or no role in the generation of electricity in 1973. The only state reporting gas consumption was Oregon, and this was in two small plants which were generally used for standby service. The total consumption of 2.4 Bcf for this area in 1973 was less than 0.1 percent of the U.S. total.

The 283 electric utility steam generating plants located in the interstate market burned 1,409.2 Bcf in 1973. Virtually all of the power generated by gas in these plants could have been fueled by either oil or coal, with the majority of the plants suffering little or no boiler derating when consuming an alternate fuel. Gas was considered to be the primary fuel in 132 of the 283 plants in which it was burned; these plants consumed 936.0 Bcf in 1973. Plants in which an alternate could have been burned numbered 95 with no boiler derating, and these plants consumed 50 percent of the gas consumed by electric utilities in the interstate market. An alternate fuel could have been burned in 34 plants with some derating, ranging from 5 to 25 percent. In 3 plants there was no alternate available for gas. Plants in which the burning of an alternate would entail some derating consumed 15 percent of the total, while those with no alternate consumed less than 1 percent. Gas was burned as a secondary fuel in 151 of the 283 plants. These plants burned 473.2 Bcf, just under 34 percent of the interstate total.

In summary, 84 percent of the gas consumed by electric utilities in these states in 1973 could have been replaced by oil or coal with no loss in generating capacity. An additional 15 percent of the gas could have been replaced under some relatively minor boiler derating. The remaining gas consumption, less than 1 percent of the total, could not have been replaced by an alternate fuel. Thus, gas curtailments in the interstate market would have minor effects on the generation capabilities of steam-electric power plants, assuming alternate fuel would be available.

In terms of alternate fuels which would have been consumed if gas had not been available, 1,043 Bcf of gas could have been replaced by oil. This represents 74 percent of the total gas consumption by electric utilities in the interstate market. Coal could have been substituted for 352 Bcf, 25 percent of the total.1/ The remaining 1 percent had no alternate available. The substitution of these fuels for gas in all boilers would result in relatively minor deratings. A total gas curtailment would decrease the megawatt rating in the interstate market by less than 2%. The majority of the plants affected are located in Nebraska, Kansas, Missouri, Arkansas, Mississippi, and Illinois.

1/ The fuel which a plant would substitute for gas may not be apparent in all cases from the information contained in Schedule V-1. For example, a plant with 8 coal boilers and 2 gas/oil boilers would have more than one option available in the event of a gas curtailment. It could: (1) increase the output of the 8 coal boilers, or (2) substitute oil for gas in the two gas/oil boilers. The estimates here are based on the boiler-by-boiler requirements in the plants and the plants' utilization of coal and oil in the past.

C. Summary of the Alternate Fuel Capabilities in the Intrastate Market

Some 58 percent of all gas consumed by the electric utility sector in 1973 was burned in the four-state area of Texas, Louisiana, Oklahoma and New Mexico. The combined consumption total for the year was 1,981.9 Bcf. The striking features of this region were: (1) gas was the primary fuel in virtually every plant (131 of 132); and (2) the majority of the plants (96 of 132) were listed as having no alternate fuel capability.

Texas was the leading gas consumer in 1973 with 80 plants burning 1,277.8 Bcf. A total of 64 of these 80 plants were listed as having no alternate capability. In the 16 plants in which an alternate could have been burned (9 of which would suffer some boiler derating), oil was the alternate fuel.

Louisiana burned 369.4 Bcf in 23 gas consuming plants, 16 of which had no alternate fuel capability. A total of 270.9 Bcf was consumed in the 16 Oklahoma plants, and 63.9 Bcf in New Mexico. In Oklahoma, 10 of the 16 plants had no alternate capability, and the ratio was 6 of 13 in New Mexico. In the plants in which an alternate fuel could have been burned, including those which would suffer some derating, oil was the choice in all plants in both Louisiana and New Mexico. In Oklahoma 4 plants listed coal as an alternate, and 2 listed oil.

At this point it becomes necessary to consider a rather important time-lag problem. As mentioned previously, the Form 36 data were submitted in early 1973. The assessment of each company with regards to its alternate fuel capability was made in light of the general conditions which prevailed at that time. Over the past two years a number of factors have significantly altered the status of some companies. The supplies and prices of fuels available to electric utilities have substantially changed, FPC and state regulatory agency activities have increased, and the general economic climate is vastly different than it was in 1973. As a result of these and other factors, some companies have been forced to make changes previously thought to be unfeasible.

The majority of the plants in the four-state area were designed to burn gas, with the possible use of oil in emergency situations. Oil combustion in a gas plant is possible, but only for short periods and usually with some boiler derating. To convert a plant from emergency oil-firing to one which could burn either oil or gas for extended periods of time, is an undertaking which requires both time and capital investment. The magnitude of these variables will depend on the original design of the specific plant under study.

Because of the proportion of plants in this area which indicated that gas was the primary fuel with no alternate available, further research was deemed necessary to ascertain the present status of the major electric utilities in the four-state region, as well as in Arkansas and Mississippi as discussed in the preceding section. The 1973 and 1974 Annual Reports to Stockholders of these companies were reviewed. The general climate in these states appears to be one of uncertainty with regards to gas supply. Not only are the gas supplies contracted on an interruptible or interstate basis thought to be in jeopardy, but also the viability of some firm intrastate contracts appears to be in question due to curtailment priorities established by state regulatory authorities. The unclear picture regarding future gas supplies has led a number of companies to diversify their fuel base, both by increasing the convertability of gas plants to oil, and by designing new plants for gas/oil, coal, lignite and nuclear fuels.

Power companies in Oklahoma have apparently seen little need for major plant conversions. Two companies burned over 90 percent of the electric utility gas in the state in 1973, and both consider their gas supplies to be in solid shape. Oklahoma Gas & Electric Co., the major electric utility in the state, operates solely with intrastate supplies and this company contracted substantial amounts of new reserves in 1974. However, they do plan a future gradual shift towards low-sulfur coal. The Public Service Co. of Oklahoma owns its supply system, with most gas reserves in the system dedicated for the life of the wells. This company has just completed what they feel may well be the last major gas-fired plant in the country, but they too foresee a future shift towards coal. The shift from gas to coal in Oklahoma is merely in the planning stages and seems to be applicable to new plants only. Thus, most plants will operate almost exclusively on gas with little conversion activity in the near future.

The situation in Louisiana is somewhat mixed, with both interstate and intrastate supplies of gas. Louisiana Power and Light Co., Gulf States Utilities Co., and New Orleans Public Service Inc. accounted for over 80 percent of the state's 1973 utility gas consumption. All three receive a portion of their gas from the same interstate supplier, and there have been serious curtailment problems with this supplier. As a result they have tried to stabilize their fuel situation by increasing their conversion potential and also by seeking more intrastate gas. Of the 10 plants operated by these three companies, six are undergoing some degree of conversion to enable them to burn oil for longer periods. The following statement from the 1973 Annual Report of New Orleans Public Service, Inc. summarizes the situation of a number of utilities in the state: "The severe curtailment of natural gas purchased under contract by the company for fuel to generate electricity has forced greatly increased use of oil as a power plant fuel. A portion of approximately $12.5 million spent on new construction during the year was needed to continue modifications begun in 1972 at Michoud and Patterson stations to permit the burning of oil for extended periods of time."

In Texas a large segment of the electric utility industry receives its gas from sources not subject to FPC regulation. Recent actions by the Texas Railroad Commission, however, have placed the status of all gas used as a boiler fuel in some doubt. The proposed phasing out of gas as a boiler fuel, coupled with higher intrastate gas prices and curtailed interstate deliveries, has caused a good deal of activity in this gas dominant state. Six of the major consuming utilities, which burned nearly 75 percent of the state's electric utility gas in 1973, indicated that operations are underway to increase their ability to burn oil. The conversions will not allow complete oil-firing in all units, but they will lessen the current dependence on gas. Millions of dollars are being spent on converting plants to a multiple fuel capability, oil storage and handling facilities are increasing, and a number of plants under design will operate on coal or lignite. The largest gas-consuming utility in the state, Houston Lighting and Power, reported in its 1974 annual report that it presently has more than 1,700,000 kilowatts of generating capacity which can burn oil or gas continuously. This amount will increase to 4,350,000 kilowatts in 1975, and 5,100,000 in the future. This company will also expand its oil storage capacity to 6.7 million barrels by 1977, and an intra-company oil pipeline is under construction.

The company was hit by curtailments of 12.3 percent by one of its two major gas suppliers in 1974, and has therefore extended and revised its second gas contract to satisfy current needs. They estimate that the new contract will provide the company with 64 percent of its fuel requirements through 1978, and 20 percent from 1979-1984. The outlook of this company typifies that of others in the state, and may be summarized by the statement that the amended gas contracts will "facilitate an orderly transition from fuel-burning capability based almost entirely on natural gas to one based on natural gas and other fuels, including oil, nuclear and coal."

The gas-burning plants in New Mexico are similar to those in Oklahoma in that gas supplies are largely of an intrastate nature, and little conversion has taken place at this time. Both the Public Service Company of New Mexico and Southwestern Public Service Company, with 6 gas plants and 60 percent of the state's 1973 consumption, expressed confidence in their natural gas supply. The Public Service Company of New Mexico emphasized a new contract which extends through 1989 and the reassurances of its intrastate suppliers, while Southwestern Public Service Company pointed out that all of its gas is intrastate and 25 percent of the reserves are from dedicated wells.

Thus, alternate fuel requirements in the four-state (intrastate) region are difficult to assess. Texas, Oklahoma, Louisiana and New Mexico plants consumed 58 percent of the

U.S. electric utility gas supply in 1973. The Form 36 data indicate that the majority of the plants in these four states (96 of 132) could burn only gas. Further research indicates that their alternate fuel capability has significantly increased since 1973, and will continue to do so in the future. Plant modifications have been most noticeable in Texas and Louisiana, two of the largest gas consumers in the electric utility sector. The companies in these two states have initiated serious efforts to diversify their fuel base. They have sought to: increase the ability of gas plants to burn oil, design future plants for multiple fuel firing, and increase experimentation with fuel forms previously unexploited in this area (coal, lignite, nuclear). The exact number of plants which have undergone conversion or will undergo conversion cannot be estimated at this time, but some efforts have been made by most utilities in the two states. Gas will continue to be the primary fuel in the near future, as long as it is available and remains a feasible energy source, but precautionary measures are being taken.

The majority of the gas plants in New Mexico and Oklahoma have little or no alternate fuel capability at this time. Due to favorable gas reserves positions, the companies in these two states have shown little desire to decrease their dependence on gas, although some mention was made of increased use of coal in future plants in both states.

Thus, this four-state region is vastly different from the rest of the country. Gas is the primary fuel in far more plants, and alternate fuels may not always be substituted for gas. A total dependence on gas exists in many more plants than in the rest of the country, but not as many as might be inferred from Schedules V-1 and V-2. Oil could have replaced 210 Bcf in the four-state area, 11 percent of total consumption in this region. Coal could have been burned in place of 27 Bcf, 1 percent of the total. A large portion of the gas burned, 868 Bcf or 44 percent, could not have been replaced by an alternate fuel. The residual 44 percent, or 877 Bcf, was of a questionable status. It was burned in plants which have undergone some conversion, but the degree of conversion is unknown at this time. It may only be said that the most probable alternative to these 877 Bcf is oil. Any estimation of the total boiler derating when burning alternate fuels in these four states would be highly speculative at this time. The overall effect would be far more significant than in the interstate market, but to determine an exact magnitude would require an extensive plant conversion study as insufficient data now exists.

D. Projections of Alternate Fuel Demand by Electric Utilities Due to Reductions in Gas Supply

Schedule V-3 shows the estimated use of alternative fuels by electric utilities due to reductions in gas supply from 1973 to 1980. The declines in gas consumption are attributed to one of three categories -- demand for coal, demand for fuel oil, and demand for indeterminate fuels. The latter category reflects plants which are indicated to have limited or no known alternative fuel burning capability at this time. By integrating the plant by plant projections of natural gas availability from Chapter IV with the plant by plant analysis of alternative fuel burning capability, the forecasts show for each state the effect of the gas shortfall on existing power plants. It should be noted that no consideration is given to the need for overall increasing generation, and the resultant increase in demand for other fuels due to the unavailability of gas.

On Schedule V-3, column (2) shows for each region and state the amount in trillions of Btu's of gas consumed in 1973. Columns (3) through (20) show, as a result of declines in gas volumes, the displaced demand for alternative fuels. For example, in 1973 electric utilities in New England burned 5.7 trillion Btu's of gas. In 1975, the reduction in gas supply from 1973 levels is estimated at 0.2 trillion Btu's. Column (4) shows that the plants suffering this reduction have alternative fuel burning capability in terms of fuel oil. Thus, it is projected that in 1975 electric utilities in New England will burn an increment of 0.2 trillion Btu's of fuel oil due to a comparable reduction in natural gas availability.

It should be noted that on the schedule certain data are shown in brackets, denoting negative demands for alternative fuels. This situation indicates that natural gas consumption is projected to increase from 1973 levels, resulting in a decline in demand for an alternate fuel. Thus, for the State of Minnesota as an example, column (4) shows a negative 1.6 trillion Btu's. This means that in gas burning plants with fuel oil burning capability, gas consumption in 1975 is projected to increase by 1.6 trillion Btu's in 1975 compared with 1973. In cases where bracketed values appear in the "indeterminate" column (see Oklahoma for example), this means that increases in gas consumption by plants which do not have alternate fuel capability are projected.

The schedule shows that in 1973 gas consumption on the part of power plants in the U.S. analyzed herein was 3436.1 trillion Btu's. In 1975, reductions in gas consumption by these plants is projected to result in the consumption of 103.6 trillion Btu's of coal and 589.7 trillion Btu's of oil. Some 27.5 trillion Btu's of the decline in gas consumption is "indeterminate" -- will take place in plants which have limited or no known alternative fuel burning capability.

By 1980 the shortfall in gas deliveries would require additional coal consumption of 348.5 trillion Btu's and additional fuel oil consumption of 1074.0 trillion Btu's. The remaining portion of the net reduction in 1973 gas consumption -- 272.6 trillion Btu's -- would take place in plants which at this time have limited or no known alternative fuel burning capability. Excluding those plants which have limited or no known alternative fuel burning capability but for which increases in gas consumption are projected, the reduction in gas deliveries by 1980 to plants which have limited or no known alternative fuel burning capability would be 348.8 trillion Btu's.

E. Deterrents to the Use of Alternate Fuels by Electric Utilities

The conversion of a gas-only plant to a coal based unit would entail major modifications to the boiler/furnace unit resulting in a substantial derating of the unit. These modifications would be of such a magnitude that the construction of a totally new and separate coal plant might offer a more feasible alternative.

Additional space at the plant site would have to be available for coal storage and intra-plant coal car movement. In addition, provisions for on-site disposal of sludge and ash might be required. Environmental quality standards would necessitate the utilization of electrostatic precipitators and possibly stack-scrubber devices for the control of ash and sulfur oxide emissions, both of which require additional plant space.

The conversion process would further be severely hampered by the physical size of the boiler/furnace unit. Gas units tend to be relatively smaller than oil or coal units due to favorable flame characteristics and also because gas is a clean burning fuel producing no waste products. Coal releases soot and ash when burned, which can cause severe corrosion and slagging problems. Slagging, the excessive accumulation of ash particles between the water tubing throughout the boiler/furnace, might not even be corrected with the addition of soot blowers unless all tubing was re-spaced at wider intervals, which entails essentially a rebuilding of the boiler. The addition of an ash hopper would require the elevation of the entire unit, which could be equivalent in size to the fourteen story building.

A conversion from gas to oil is a far more manageable task, although a number of modifications would have to be made for continuous oil-firing. Gas recirculation fans would have to be added to: prevent the overheating of wall tubing, aid in increasing super reheat temperatures, and reduce sulfur oxide emissions. The clogging caused by ash deposits would require the installation of soot blowers, and also necessitate periodic water washings. Additional superheat and reheat surfaces would be required because of the lower temperature of the oil-firing process, a situation only partially alleviated by the addition of gas recirculation fans. The oil flame would create a high heat flux in the wall tubes, and these tubes would tend to overheat if the flame was of a sufficient size to obtain maximum plant capacity. Thus the unit might be forced to operate below capacity.

Plant site modifications would include the addition of unloading and storage facilities, as well as pumping and heating stations (for fuels that are viscous) if pipeline deliveries were to be used. Two final modifications necessary for residual, but not distillate oil-firing, would be the addition of steam coil air heaters and a small ash hopper. If low-sulfur oil (less than seven-tenths of one percent) was not available, high-sulfur oil would further complicate the conversion process. Measures would have to be taken to prevent vanadium corrosion, and the higher ash and sulfur contents would require the use of electrostatic precipitators and some type of SO_2 emission control device as in the case of gas-coal conversion. Finally, sludge and ash disposal would again have to be dealt with.

The cost of converting facilities from gas to other fuels will vary from plant to plant. As an example, evidence before the Texas Railroad Commission by Houston Lighting and Power Company in the proposed curtailment plan case of Penzoil Pipeline Company indicates that the cost is substantial. In 1973 Houston Lighting and Power Company operated ten steam-electric plants with a generating capacity of 7,375 megawatts.

The company felt that a conversion to coal was virtually impossible, and that a conversion to oil for all units would require a project seven to ten years in duration with an investment in excess of $100,000,000 ($13.56/kilowatt of capacity in 1973 dollars).

In many instances there may be little economic incentive for utilities to burn alternate fuels. Generally, gas is a lower priced fuel than either oil or coal. In 1974, the average price of gas burned by electric utilities was 48¢/MMBtu, compared with 71¢/MMBtu for coal and 192¢/MMBtu for oil. For gas-only plants, oil is a more feasible alternative than coal from an engineering standpoint, but the price disparity between gas and oil is large enough to deter any unnecessary conversions.

F. The Relative Role of Natural Gas as an Electric Utility Boiler Fuel by Region

Natural gas has become a major source of energy for electric utilities in the United States, but the role of this fuel will decline as the gas shortage and resulting curtailments increase. Gas provided over 18 percent of the utility sectors total Btu requirements in 1973, more than fuel oil, nuclear, or hydroelectric sources, but less than coal. The level of dependence on gas varies considerably from state to state, as is shown on schedule V-4 which sets out the percent contribution to total energy consumption of the six primary power sources for electric utilities.

The use of gas is most significant in four FRC regions: the Northern Plains, Mid Continent, Pacific Southwest, and Gulf Coast. The percent of total utility energy needs met by gas in these regions ranged from 23 percent in the Northern Plains to 82 percent in the Gulf Coast in 1973. All states in these regions place a heavy reliance on gas, with the exceptions of North Dakota and South Dakota.

The utilities in five of the remaining six FRC regions rely on fuel oil or coal to a much greater extent than gas to meet their energy needs. In these regions only Florida, Colorado, and Utah derived more than 10 percent of their total requirements from gas. However, even though the market share of gas in some of these states is small, the impact of a curtailment should not be minimized. For example, gas supplied less than 7 percent of the power for New York utilities in 1973, but this amounted to 47 Bcf and a total curtailment would require the substitution of 7.7 million barrels of oil or 2.1 million tons of coal.